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BEFORE THE ARIZONA CORPORATION COMMISSION

Arizona Corporation Commission
DOCKETED
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DOCKETED BY

COMMISSIONERS

GARY PIERCE, Chairman
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	Docket No. E-01345A-11-0224 **NOTICE OF FILING DIRECT TESTIMONY (REVENUE REQUIREMENT) AND ATTACHMENTS OF KEVIN C. HIGGINS ON BEHALF OF FREEPORT-MCMORAN COPPER & GOLD INC. AND ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION**

Freeport-McMoRan Copper & Gold Inc. and Arizonans for Electric Choice and Competition (collectively "AECC"), hereby submit the Direct Testimony (Revenue Requirement) and Attachments of Kevin C. Higgins on behalf of AECC in the above captioned Docket.

An unredacted copy of Page 4 of Attachment KCH-4 will be available to parties who have executed a Confidentiality Agreement.

RESPECTFULLY SUBMITTED this 18th day of November 2011.

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BEFORE THE ARIZONA CORPORATION COMMISSION

In the Matter of the Application of Arizona	)	
Public Service Company for a Hearing to	)	
Determine the Fair Value of the Utility	)	
Property of the Company for Ratemaking	)	Docket No. E-01345A-11-0224
Purposes, to Fix a Just and Reasonable	)	
Rate of Return Thereon, to Approve Rate	)	
Schedules Designed to Develop Such Return	)	

Direct Testimony of Kevin C. Higgins

on behalf of

Freeport-McMoRan Copper & Gold Inc. and

Arizonans for Electric Choice & Competition

Revenue Requirement

November 18, 2011

DIRECT TESTIMONY OF KEVIN C. HIGGINS

TABLE OF CONTENTS

DIRECT TESTIMONY OF KEVIN C. HIGGINS

INTRODUCTION

Q. Please state your name and business address.

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by Freeport-McMoRan Copper & Gold Inc. and Arizonans for Electric Choice and Competition ("AECC"). AECC is a business coalition that advocates on behalf of retail electric customers in Arizona.[1]

Q. Please describe your professional experience and qualifications.

A. My academic background is in economics, and I have completed all coursework and field examinations toward the Ph.D. in Economics at the University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist

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[1] Henceforth in this testimony, Freeport-McMoRan Copper & Gold Inc. and AECC collectively will be referred to as "AECC."

private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

Q. Have you testified before this Commission in other dockets?

A. Yes. I have testified in a number of proceedings before this Commission, including the generic proceeding on retail electric competition (1998),[2] the hearings on the Arizona Public Service Company ("APS") 1999 Settlement Agreement (1999),[3] the hearings on the Tucson Electric Power ("TEP") 1999 Settlement Agreement (1999),[4] the AEPCO transition charge hearings (1999),[5] the Commission's Track A proceeding (2002),[6] the APS adjustment mechanism proceeding (2003),[7] the Arizona ISA proceeding (2003),[8] the APS 2004 rate case (2004),[9] the Trico 2004 rate case (2005),[10] the TEP 2004 rate review (2005),[11] the APS 2006 interim rate proceeding (2006),[12] the APS 2006 rate case (2006),[13]

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[2] Docket No. RE-00000C-94-0165.
[3] Docket Nos. RE-00000C-94-0165, E-01345A-98-0471, and E-01345A-98-0473.
[4] Docket Nos. RE-00000C-94-0165, E-01933A-97-0772, and E-01933A-97-0773.
[5] Docket No. E-01773A-98-0470.
[6] Docket Nos. E-00000A-02-0051; E-01345A-01-0822; E-00000A-01-0630; E-01933A-02-0069; E-01933A-98-0471.
[7] Docket No. E-01345A-02-0403.
[8] Docket No. E-00000A-01-0630.
[9] Docket No. E-01345A-03-0437.
[10] Docket No. E-01461A-04-0607.
[11] Docket No. E-01933A-04-0408.
[12] Docket No. E-01345A-06-0009.

TEP's request to amend Decision No. 62103 (2007),[14] the 2007 TEP rate case (2008),[15] and the APS 2008 rate case (2008).[16]

Q. Have you testified before utility regulatory commissions in other states?

A. Yes. I have testified in approximately 135 other proceedings on the subjects of utility rates and regulatory policy before state utility regulators in Alaska, Arkansas, Colorado, Georgia, Idaho, Illinois, Indiana, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, New York, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, Texas, Utah, Virginia, Washington, West Virginia, and Wyoming. I have also participated in various Pricing Processes conducted by the Salt River Project Board and have filed affidavits in proceedings at the Federal Energy Regulatory Commission.

A more detailed description of my qualifications is contained in Appendix A, attached to this testimony.

OVERVIEW AND CONCLUSIONS

Q. What is the purpose of your testimony in this phase of the proceeding?

A. My testimony addresses five major topics:

(1) APS's request for a base rate increase of $95.5 million relative to test year base revenues;

(2) The appropriate level of nuclear decommissioning costs recovered from customers through the System Benefits Charge;

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[13] Docket No. E-01345A-05-0816.
[14] Docket No. E-01933A-05-0650.
[15] Docket No. E-01933A-07-0402.
[16] Docket No. E-01345A-08-0172.

(3) APS's proposal to change the sharing mechanism in the Power Supply Adjustor ("PSA");

(4) APS's proposal for adoption of a revenue decoupling mechanism; and

(5) APS's proposal for adoption of an Environmental and Reliability Account. In my testimony, I recommend adjustments to APS's proposals that I believe are necessary to ensure results that are just and reasonable.

Relative to the wide scope of this general rate proceeding, my recommended adjustments are concentrated on a limited number of issues. Absence of comment on my part regarding a particular issue does not signify support (or opposition) toward the Company's filing with respect to the non-discussed issue. In particular, AECC is not filing testimony on the subject of allowed return on equity, in that AECC anticipates that this subject will be addressed by Staff and RUCO. The absence of specific AECC testimony on this subject should not be construed as support for the 11.0% return on equity proposed by APS in this proceeding.

Q. What are the primary conclusions and recommendations presented in your testimony?

A. (1) I recommend that APS's revenue requirement for its base rates be reduced by at least **$75.392** million relative to the $95.494 million base rate increase proposed by APS in its Application. This reduction does not take into account adjustments that may be offered by other parties with respect to return on equity or other revenue requirement items not addressed in my testimony.

(2) I recommend that APS's System Benefits Charge be reduced by **$8.704** million per year to better reflect the reduction in decommissioning costs associated with the Palo Verde Nuclear Generating Station life extension.

(3) I recommend that APS's proposed elimination of the 90/10 sharing provision in the PSA be rejected by the Commission. If the Commission is interested in revisiting the question of the appropriate sharing proportions in the PSA, then I strongly encourage the Commission to consider adopting the 70/30 sharing proportion that was recently approved in Wyoming and Utah.

(4) I recommend that the Commission reject APS's decoupling proposal for all customers. If, however, some form of revenue decoupling is approved by the Commission, I recommend that customers with billing demands greater than 400 kW (i.e., Rate Schedules 32-L, 34, and 35) be excluded from the program. Rate Schedules 34 and 35 already have rate designs that insulate APS from loss of fixed-cost recovery from energy conservation. The design of Rate Schedule 32-L can be modified to achieve a comparable result.

(5) APS's proposed Environmental and Reliability Account is an example of unwarranted single-issue ratemaking, and should be rejected by the Commission.

<u>ADJUSTMENTS TO BASE REVENUE INCREASE</u>

Q. What increase in base revenues is APS recommending in this case?

A. In its Application, APS is recommending a base rate increase of $95.5 million relative to test year base revenues. This increase includes the net effects of two important components: (1) a $143.5 million <u>decrease</u> in fuel expense included in base rates; and (2) an increase of $44.9 million from transferring the revenue requirements of certain utility-owned renewable energy projects from the RES Tariff into base rates. After netting the effects of these two components, the non-fuel base rate increase embedded in APS's proposal amounts to $194.1 million. In addition, APS has indicated in discovery responses that the Company intends to make several adjustments to its proposal, collectively reducing its filed request to increase base rates by $10.6 million to $84.9 million, as will be discussed later in my testimony. For presentation purposes, the revenue requirements adjustments in my testimony will be applied to the revenue requirements presented in APS's filed Application.

Q. Do you have any recommended adjustments to APS's proposed base rate increase?

A. Yes. I am recommending a reduction of **$75.392** million to APS's proposed base rate increase relative to the Company's Application. This recommendation is summarized in Attachment KCH-1 and consists of the following adjustments, each of which will be discussed in turn:

Table KCH-1

Summary of AECC Adjustments to APS Revenue Requirements
(Base Rates)

	Original Cost Increase/ (Decrease)	Fair Value Increase/ (Decrease)	Total Increase/ (Decrease)	Total Adjustment Impact
APS - As Filed Requested Increase	$ 54,610	$ 40,884	$ 95,494	
APS - Identified Updates	42,646	42,263	84,909	(10,585)
AECC Post-Test Year Plant Adjustment	3,660	50,257	53,917	(30,992)
AECC Sales Growth Adjustment	(20,227)	50,257	30,030	(23,887)
AECC Renewable Generation Above Market Adj.	(32,891)	52,993	20,102	(9,928)
AECC Adjustment Total				$ (75,392)

APS-Identified Update Adjustments

Q. What adjustments to its filed case has APS identified in discovery?

A. In discovery, APS has identified eight changes to its filed case that the Company indicates it supports going forward. These changes relate to the Company's post-test year plant additions, payroll annualization, property tax expense, base fuel and purchased power expense, research and development project costs, step-up transformer costs, cash working capital, and APS's proposed fair value increment. Collectively, these changes reduce APS's proposed revenue requirement by **$10.585** million to $84.909 million.

Q. What is your recommended treatment of these APS-identified changes?

A. I recommend that the Commission accept these APS-identified changes as the revised "starting point" for APS's requested revenue requirement. Accordingly, I have provided an adjustment in my testimony for these changes as the first revenue requirement adjustment that I am recommending. This adjustment is presented in Attachment KCH-1, page 2, columns (d) and (e).

Post-Test Year Adjustments

Q. What is meant by the term "test year" as used in ratemaking?

A. "Test year" refers to a discrete twelve-month period that is used as the basis for setting utility rates in a general rate proceeding. This term is often used interchangeably with the term "test period," although some jurisdictions make a fine distinction between the two, with "test year" referring to the baseline period for which underlying historical financial and operating data must be reported and "test period" referring to the twelve-month period used for setting rates. When this distinction is made, test year and test period can be coterminous, overlapping, or entirely distinct time periods.

Q. What test year is APS using in its application?

A. Officially, the test year that APS is using for revenue requirement purposes is Calendar Year 2010. As such, APS begins its analysis by presenting a Calendar Year 2010 baseline that sets out the Company's twelve-month revenue, expense, and investment levels. These results are then adjusted for ratemaking purposes, which is typical in most general rate proceedings. However, in most ratemaking contexts, the test period analysis that results from such adjustments can be readily described with reference to a discrete time period, e.g., "2010 historical test year with known and measureable changes through 12/31/11," or "2011 projected test period," etc.

APS's filing defies such a clear description. While the basis of the Company's filing starts with 2010 actual revenues, expenses, and investment, the filing incorporates various revenue, expense, and investment elements that are adjusted for values that either occurred or are projected to occur variously in 2011 or 2012, but without adhering to a consistent time frame for all adjustments. The disparate time frames used by APS for its test period adjustments are highlighted in Table KCH-1, below, which identifies the time period applicable to selected APS proposed adjustments.

Table KCH-1

Time Frame for Various APS-Proposed Adjustments

Adjustment	**Time Frame for Valuation**	**Reference**
Rate Base	New plant through 6/30/12.	La Benz, p. 18
Employee count	March 2011 level.	La Benz, p. 23; JCL_WP23
Wages	March 2011 level.	La Benz, p. 23; JCL_WP23
Employee benefits	Actuarial valuation of 2011 benefits expense.	La Benz, p. 23; JCL_WP24
Property taxes	Current (2011) rates on 12/31/10 values.	La Benz, p. 24 JCL_WP26
Non-fuel O&M Expenses	Year ended 2010, adjusted for post-test year plant additions through 6/30/12.	Attachment JCL-8
Fuel Expense	Expected calendar year 2012 fuel and purchased power prices, at adjusted test year consumption.	Ewen, p. 3, 10
Retail sales	Year ended 12/31/10.	SFR, E-9

In my view, APS's blending of a Calendar Year 2010 test year with adjustments that are from disparate time periods results in a test period that is ill-defined and unsynchronized.

Q. What do you mean by "unsynchronized" test period?

A. A test period is considered to be fully synchronized when all elements used in ratemaking – i.e., rate base, revenues, and expenses – correspond to the very same time period, both with respect to the twelve-month period selected for measurement (e.g., Calendar Year 2010) as well as <u>when</u> during the selected period these values are being measured (i.e., end-of-period values versus average-of-period values). Conversely, a test period is considered to be unsynchronized when all elements used in ratemaking do *not* correspond to the same time period.

Q. In general, is it preferable for test periods to be fully synchronized?

A. Yes. A fully-synchronized test period adheres to what is known as the "matching principle." Measuring rate base, revenues, and expenses over the same twelve-month period and in the same manner (i.e., end-of-period or average-of-period) properly aligns these major ratemaking elements, ensuring the most reasonable basis for measuring whether the utility's rates provide it with a reasonable opportunity to earn its authorized rate of return. In contrast, an unsynchronized test period creates the potential for mismatches among ratemaking elements that distort the proper measurement of the utility's rate of return over the test period. I will provide an example of a problematic mismatch in APS's filing later in my testimony when I discuss the implications of bonus tax depreciation as it pertains to APS's proposed post-test year plant additions.

Q. What is APS recommending with respect to post-test year adjustments?

A. APS is proposing that several sets of post-test year adjustments be recognized for ratemaking purposes. In the aggregate, these post-test year adjustments add $432.2 million in total Company rate base[17] and $41.6 million in total Company expense[18] associated with facilities that are scheduled to come on line after December 31, 2010, but which are projected to be in service by June 30, 2012. The revenue requirement increase associated with the post-test year plant additions (in APS's Application) is $77.3 million.[19]

The Company's proposed post-test year adjustments fall into four categories: solar generation, fossil generation, nuclear generation, and distribution

[17] Source: APS Attachment JCL-7.

[18] Source: APS Attachment JCL-8.

[19] On page 4 of its Application, APS indicates that the revenue requirement impact is $48.9 million; however, APS notes that this figure excludes the solar generation plant additions.

and general and intangibles. Collectively, these plant additions appear to correspond to the full universe of plant additions that APS plans to bring into service between January 1, 2011 and June 30, 2012.

Q. What is your assessment of APS's proposal for post-test period adjustments?

A. In general, APS's proposal for post-test period additions is problematic in that it attempts to recover a return on (projected) new plant in service and associated depreciation expense that is not synchronized with the underlying test year. One conceptual problem with this unsynchronized approach is that the cost of new plant added through June 30, 2012 would be recovered in rates that are calculated based on the level of retail sales that existed at the end of 2010, rather than the sales that are projected for mid-2012, consistent with the proposed recovery of the cost of the new plant. In addition, there are other technical problems with APS's proposal that I will address in more detail a little later in my testimony.

On the other hand, I recognize that cost recovery for post-test period plant additions was included in the APS 2008 general rate case Settlement Agreement. I am also aware that APS has faced challenging financial circumstances in past years, including a downgrade to its credit rating by S&P in 2005 to BBB-.[20] Notably, S&P's downgrade was reversed back to BBB this past summer. Having been a participant in each of APS's major rate filings since 1999, I believe that recognition of post-test period plant additions in the prior rate case contributed to the improvement in APS's credit metrics.

[20] S&P's downgrade occurred on December 21, 2005. This was followed by a downgrade from Fitch on January 30, 2006.

The case for some recognition of post-test period plant additions is given additional support in light of the consideration that APS may not have the ability to pursue the more straightforward option of filing a rate case using a fully-projected (i.e., future) test period, an option that is available to many other utilities. R14-2-103 defines test year as "the one-year *historical* period used in determining rate base, operating income and rate of return." [Emphasis added] R14-2-103 goes on to state that "the end of the test year shall be the most recent practical date available prior to the filing." While I can offer no legal opinion on this language, one possible interpretation is that only historical test periods may be used to set rates in an APS rate case. For a utility that is adding substantial capital investment, limiting cost recovery to plant that is in service no later than December 31, 2010 – for a rate effective period starting in 2012 – creates predictable concerns about regulatory lag. The inclusion of post-test period plant is an obvious attempt to address this concern while maintaining the formality of an historical test period.

Q. Given the preceding discussion, do you support APS's proposed post-test year plant additions adjustment as filed?

A. No, I do not. I support some recognition of post-test year plant additions, but not as proposed by APS. I have three specific objections to APS's proposal, which I address through two adjustments. In addition, I have a separate objection and adjustment to a portion of the solar generation plant additions, which I address through a third adjustment later in my testimony.

Q. Please proceed. What is your first basis for objecting to APS's proposal for a post-test year adjustment in the form requested by the Company?

A. The first basis is that APS proposes to recognize its post-test period rate base adjustments as projected end-of-period values rather than average-of-period values.

Q. What does it mean for rate base to be projected to an end-of-period value?

A. It means that for the purpose of setting rates, APS is proposing to use its forecasted value of the rate base additions on the last day of the its proposed measurement period for the plant additions, June 30, 2012.

Q. Please explain your disagreement with APS regarding the use of end-of-period rate base for the plant additions.

A. The sole justification for using an end-of-period rate base is to address utility concerns about regulatory lag. According to the regulatory lag argument, utilities are challenged to earn their authorized rates of return on investment during periods of system expansion when historical test periods are used for setting rates. One means of reducing regulatory lag is to use a projected test period – or in this instance, an adjustment for projected plant additions – rather than a strictly historical measurement period. An entirely separate means of reducing regulatory lag is to adjust rate base in an <u>historical</u> test period to an end-of-period value, as this will cause the utility's authorized rate of return to be applied to the year-ending value of net plant in service. To this end, APS already uses end-of-period values for its Calendar Year 2010 test year (in addition to various adjustments that apply 2011 and 2012 values, as noted above).

However, in offering its plant additions adjustment, APS proposes to combine <u>both</u> a projected measurement period <u>and</u> an end-of-period rate base. This "doubling up" of attrition mitigation proposals is unorthodox and unreasonably aggressive. In my experience, jurisdictions seldom allow end-of-period values to be used for a projected (or forecasted) test period or measurement period. In a recent example, in its 2009 general rate case in Wyoming, PacifiCorp attempted to combine an end-of-period rate base with a projected test period. Although the revenue requirement for the case was resolved through stipulation, the Wyoming Commission expressly prohibited PacifiCorp from filing its next rate case using the combination of a future test period and an end of period rate base.

> In the event the Company makes a filing using a forecast test year, the Commission expects it to utilize an average rate base and not an end-of-period rate base. If the Company seeks to use an end-of-period rate base, it must include *in the application* a persuasive demonstration that its use would be appropriate. In addition, if the Company uses a forecast test year in its next application, it must [i] present the application using an average rate base and [ii] submit historical test year data, adjusted for known and measurable changes. In Paragraph 25 of the *Stipulation*, the Company has agreed to submit historical test year data with its next general rate case application for informational purposes.[21] [Italics in original.]

In short, an end-of-period rate base should only be contemplated when applied to an historical test period or measurement period. The proper measurement for a projected rate base is average-of-period value. Since the value of rate base changes each month as new plant is added and existing plant depreciates, determining rate base by averaging each month's value ensures that the asset base upon which the utility will earn a return is reflective of its "typical" value during the course of the test period or measurement period.

Q. What is your recommended change to APS's post-test year plant additions to address this concern?

[21] Wyoming Public Service Commission, Docket No. 20000-352-ER-09 (Record No. 12310), et al. Final Order at 33.

A. I recommend that the rate base used for APS's post-test year plant additions be modified to an average-of-period value over the post-test year measurement period, January 1, 2011 through June 30, 2012. The change is presented in Attachment KCH-2. This adjustment reduces the APS revenue requirement by approximately **$30.992** million.

Q. What is your second basis for objecting to APS's proposed post-test year adjustment?

A. Earlier in my testimony I discussed the problems of using an unsynchronized test period for ratemaking, and I cited the treatment of bonus tax depreciation as an example of a particularly problematic mismatch that complicates APS's proposed adjustment for post-test year plant additions. Properly recognized, bonus tax depreciation results in a reduction in rate base for ratemaking purposes. However, APS's post-test year adjustment wholly fails to recognize bonus tax depreciation.

Q. What is bonus tax depreciation?

A. Bonus tax depreciation refers to a greatly accelerated tax deduction for depreciation that has been permitted pursuant to several statutes signed into law in recent years to stimulate the economy. For example, bonus tax depreciation was permitted in 2008 and 2009 pursuant to the Economic Stimulus Act of 2008 and the American Recovery and Reinvestment Act of 2009. Generally, these acts permitted a first-year deprecation tax deduction equal to 50 percent of the cost of qualified property. According to the provisions of the American Recovery and Reinvestment Act of 2009, bonus tax depreciation was initially scheduled to end on December 31, 2009.

Q. **Was bonus tax depreciation been extended beyond 2009?**

A. Yes. Bonus tax depreciation was extended by the passage of two pieces of legislation in 2010. First, on September 27, 2010, the Small Business Jobs Act was signed into law. This act extended 50 percent bonus tax depreciation through December 31, 2010. Then, on December 17, 2010, the Tax Relief, Unemployment Insurance and Job Creation Act of 2010 was signed into law. This act increased bonus tax depreciation from 50 percent to 100 percent for qualified property acquired and placed into service on or after September 9, 2010 through December 31, 2011. In addition, 50 percent bonus tax depreciation was extended from January 1, 2012 through December 31, 2012.

Q. **How does bonus tax depreciation impact ratemaking for regulated utilities?**

A. Bonus tax depreciation is a form of accelerated tax depreciation, which is not a new phenomenon for regulators. Regulatory authorities have long contended with the fact that utility depreciation for tax purposes differs from utility book depreciation used in ratemaking. Generally, the tax benefits of accelerated depreciation are not passed through directly to ratepayers; indeed, there are restrictions on doing so applied by the Internal Revenue Service ("IRS"). Instead, the difference between the utility's tax expense calculated on a book basis (normalized tax expense) and its actual cash taxes payable (calculated on a tax basis) is recorded as accumulated deferred income tax ("ADIT"). ADIT represents tax expense accrued in the current period, but which is payable in a future period. According to the conventions of income tax normalization, the temporary cash benefit of a utility's ADIT is viewed as a source of zero-cost capital to the utility in the ratemaking process. Consequently, ADIT is booked as a credit against rate base, thereby reducing revenue requirements for customers.

Bonus tax depreciation affects rates through the same mechanics as standard accelerated depreciation – that is, it results in an increase in ADIT that is applied as a credit against rate base. Significantly, however, because bonus tax depreciation represents an extraordinary acceleration of depreciation for tax purposes, the impact of bonus tax depreciation on ADIT (and, consequently, on customer rates) is more dramatic than standard accelerated depreciation in the several years immediately following the placement of the qualifying plant into service.

Q. What are the implications of bonus tax depreciation for this rate case?

A. APS's filing includes the effects of bonus tax depreciation as applied to its Calendar Year 2010 test year rate base, but does not recognize any bonus tax depreciation for the plant additions projected to come on line between January 1, 2011 and June 30, 2012, even though these investments are eligible for bonus tax depreciation treatment. Consequently, the rate base additions being proposed by APS for the post-test year plant additions are materially overstated. By not reflecting bonus tax depreciation in its post-test year plant adjustment, APS is understating the amount of ADIT; by understating the amount of ADIT, APS is overstating rate base, and thus, overstating the revenue requirement associated with its post-test year plant additions.

Q. Have you asked APS to explain why it has excluded the effects of bonus tax depreciation from its post-test year plant additions adjustment?

A. Yes. According to APS's response to AECC 1.11.b:

> Consistent with the 2007 [sic] ACC Settlement, estimated projections of future unrealized deferred taxes related to post-Test Year plant additions (in this instance the period between January 1, 2011 and July 31, 2012) are not reflected in the Total Company and ACC Jurisdiction pro forma earned rate of returns. Inclusions of any such estimated projection of deferred taxes may be deemed by the IRS as inconsistent with the historical Test Year method generally used for cost of service and ratemaking purposes. Without guidance from the IRS that explicitly allows such inclusions, APS believes using such methodology would not be appropriate and could result in extremely unfavorable tax consequences to the Company and its customers.

Q. What is your assessment of this explanation?

A. There are several components to APS's explanation. The first sentence of APS's response indicates that the benefits of bonus tax depreciation were not passed on to customers in the post-test year adjustments included in the <u>prior</u> rate case. I concur. My response to this observation is that the 2009 Settlement[22] was a complex, negotiated package. The failure to recognize (or choice not to recognize) the benefits of bonus tax depreciation associated with post-test year plant additions in a negotiated settlement does not imply that it is reasonable or proper to ignore this benefit to customers as part of a litigated proceeding.

The second and third sentences suggest that recognizing bonus tax depreciation as part of the post-test year additions might run afoul of IRS regulations. The background to APS's argument is that the Internal Revenue Code §168 requires that in determining rates using a cost-of-service methodology, utilities must use the normalization method (as I described above) to calculate Federal income tax expense. Utilities that fail to use the normalization method may lose the option of using accelerated depreciation for tax purposes. This, presumably, is the "unfavorable tax consequence" referenced by APS.

[22] APS's Response to AECC 1.11.b mistakenly refers to the "2007" ACC Settlement. The Settlement Agreement in the prior general rate case, which incorporated certain post-test year adjustments, was submitted to the Commission on June 12, 2009.

At issue is whether the IRS would determine that recognition of bonus tax depreciation applicable to APS's post-test year plant is a normalization violation. In responding to this concern, I note that as a threshold matter, any recognition of bonus tax depreciation applied to post-test period plant additions can (and ought to) be implemented by means of booking the requisite amount of additional ADIT – an approach that is entirely consistent with the normalization method. I believe the concerns expressed by APS stem not so much from whether the implementation mechanics of recognizing bonus tax depreciation would ignore normalization principles, but rather the risk that the IRS would deem the recognition of bonus tax deprecation to be a normalization violation solely because it was calculated using *an unsynchronized test period.* As discussed by APS in its response to Staff 19.14.a:

> [IRS regulations require] that the reduction in rate base [through ADIT] be synchronized with the quantity of deferred taxes reflected in cost of service. The Company is concerned that the incremental ADIT associated with post-test period plant fails to satisfy this requirement insofar as it was never included in cost of service.

In other words, the concern is not that recognizing bonus tax depreciation would be inconsistent with the *principles* of income tax normalization, but that such recognition might be construed by the IRS to be a technical violation of its regulations because the incremental ADIT would be applied to an unsynchronized test period. Although the potential for this type of adverse ruling is identified by APS as a risk, the Company has not cited any specific rulings by the IRS on the treatment of bonus tax depreciation in circumstances comparable to this general rate case that affirm this interpretation.[23]

The irony of this situation should be readily apparent. APS proposes an unsynchronized, post-test year adjustment to rate base in order to boost its revenues and mitigate regulatory lag. Ordinarily, the introduction of new plant in service would be accompanied by recognition of bonus tax depreciation in the form of additional ADIT, which in turn would be an offset to rate base – mitigating the impact of the new plant on customer rates. But not in APS's proposal. Because APS's treatment of post-test period plant is unsynchronized with its historical test period, there is an apparent risk that the IRS would deem recognition of incremental ADIT to be a normalization violation, resulting in unfavorable tax consequences. Therefore (according to APS), customers should forego the benefits of incremental ADIT, and rates should be set as if bonus depreciation does not apply to the plant additions – even though it does. The upshot of this reasoning is that APS gets to charge higher rates than would otherwise be the case. From a ratemaking perspective, this outcome is wholly unsatisfactory.

Q. Has APS provided information that allows you to estimate the revenue requirement impact of recognizing bonus tax depreciation associated with its post-test year plant additions adjustment?

A. Yes. Based on information provided by APS in response to AECC Data Request 1.11.c, I estimate that recognizing bonus depreciation in the post-test year

[23] In APS's Response to Staff 19.14.a, APS provides an explanation of the theory supporting its assertion of risk, but identifies no specific findings by the IRS for the specific circumstances at issue in this case.

plant additions would reduce the APS revenue requirement in the approximate range of $8 million to $13 million.

Q. What ratemaking treatment are you recommending for bonus tax depreciation applicable to post-test year plant additions?

A. The prospect of awarding APS an increase in rates attributable, in part, to post-test year plant additions, but which does not recognize bonus tax depreciation is extremely unpalatable. However, rather than risk the potential IRS sanction, I recommend that the Commission consider this issue in the context of my recommendation, discussed on pages 12-15 of this testimony, to use an average-of-period value for measuring the post-test period rate base additions. That is, even though my argument to use average-of-period stands on its own merit, this argument should be given even greater weight in light of the bonus tax depreciation considerations discussed here. Recognizing the plant additions as an average-of-period value, while foregoing the bonus tax depreciation benefit to avoid the IRS sanction risk, represents a middle ground position that is more than fair to APS. On the other hand, if bonus tax depreciation is not recognized, it would be particularly egregious for APS to be awarded recovery of post-test year plant additions measured at end-of-period values.

Q. What is your third basis for objecting to APS's proposed post-test year adjustment?

A. As I stated on page 11 of this direct testimony, one of the conceptual problems with APS's unsynchronized approach is that the cost of new plant added through June 30, 2012 would be recovered in rates that are calculated based on the level of retail sales that existed at the end of 2010, rather than the sales that are projected for mid-2012, consistent with the proposed recovery of the cost of the new plant. In my view, this mismatch is entirely inappropriate. One of the major reasons for installing new plant in the first place is to serve new load and projected new load over the long term. Including the costs of new facilities through the middle of 2012, but not recognizing the projected new load over that same time period, is unreasonable.

Q. What is your recommendation to the Commission on this issue?

A. I recommend that the Commission approve an adjustment to APS's retail load that corresponds to the time period being used to reflect plant additions. As I am recommending an average-of-period plant additions adjustment which has the midpoint of September 30, 2011, I recommend using the twelve-month load forecast with the same midpoint for the level of retail sales (April 1, 2011 through March 31, 2012). I am using a load forecast prepared by APS for this period.

After accounting for increased fuel expense associated with load growth, this adjustment results in a decrease of **$23.887** million to APS's revenue requirement. This calculation is presented in Attachment KCH-3.

Q. Does the load forecast you are recommending for setting APS's rates take into account projected savings from APS's energy efficiency programs?

A. Yes. I am using an APS load forecast that is inclusive of savings from DSM and energy efficiency.

Transfer of Renewable Energy Costs into Base Rates

Q. What is APS proposing with respect to the transfer of renewable energy costs into base rates?

A. A portion of the post-test year plant additions that APS is proposing to include in base rates is associated with three of APS's renewable energy programs: AZ Sun, the Schools and Government Program ("S&G Program"), and the Community Power Project – Flagstaff Program ("CPP"). As described in the direct testimony of APS witness Jeffrey B. Guldner, costs for these programs are currently recovered through the Renewable Energy Surcharge ("RES").

APS's post-test year plant additions adjustment, as filed, includes three AZ Sun projects, totaling 50 MW, that are projected to be in service by June 30, 2012. As provided in Decision No. 71502, the first 50 MW of AZ Sun is being recovered through the RES Tariff until the investment is included in base rates or another recovery mechanism, as determined in this rate case.

The S&G program is expected to deploy 8 MW of APS-owned assets by June 30, 2012 and the CPP will add another 1.5 MW by December 2011.

Q. What is the impact on base rates of APS's proposed adjustment?

A. APS's proposed adjustment (as filed) would increase total Company rate base by $267,633,000 and operating expense by $12,385,000. The associated revenue requirement increase in jurisdictional base rates is $44.9 million. This increase in base rates would displace recovery through the RES Tariff. As part of the APS-identified adjustments discussed previously in my testimony, the revenue requirement of the solar generation plant additions was reduced by $2.9 million to $42.0 million.

Q. Do you have any objections to APS's proposal for inclusion of post-test year solar generation costs that are in addition to the objections you have presented above concerning the post-test year plant additions as a whole?

A. Yes. As a distinct matter, APS's proposal for post-test year solar generation costs includes costs that exceed the Market Cost of Comparable Conventional Generation, as this term is defined in R14-2-1801.K. According to this provision of the RES Rule:

> "Market Cost of Comparable Conventional Generation" means the Affected Utility's energy and capacity cost of producing or procuring the incremental electricity that would be avoided by the resources used to meet the Annual Renewable Energy Requirement, taking into account hourly, seasonal, and long-term supply and demand circumstances. Avoided costs include any avoided transmission and distribution costs and any avoided environmental compliance costs.

The RES tariff is expressly intended to recover the costs of qualifying resources in excess of the Market Cost of Comparable Conventional Generation. R14-2-1808.B.4 provides that the utility's RES tariff filing shall provide "data to demonstrate that the Affected Utility's proposed Tariff is designed to recover only the costs in excess of the Market Cost of Comparable Conventional Generation." As the RES tariff and the accompanying RES Adjustor rate have been created for the very purpose of recovering these above-market costs, it is, in my view, unreasonable to shift the cost recovery for above-market costs into base rates. Rather, base rates should only be used for recovery of renewable generation undertaken to comply with the RES tariff <u>up to</u> the amount of the Market Cost of Comparable Conventional Generation.

Q. The solar generation costs that APS is seeking to include in the post-test year plant adjustment is utility-owned. Does the RES Rule make any distinctions between utility-owned renewable generation and third-party-owned

renewable generation (that may be purchased by utilities) with respect to the treatment of above-market costs?

A. No. The purpose of the RES Adjustor is to recover costs that are in excess of the Market Cost of Comparable Conventional Generation. There is absolutely no distinction in the Rule between utility-owned generation and generation that is purchased from third parties. Indeed, there is no logical or equitable reason to make such a distinction. Above-market cost is above-market cost: it matters not whether it derives from a utility-owned facility or a utility purchase from a third party.

Q. Why is it important for above-market renewable energy costs to continue to be recovered in the RES Adjustor rather than base rates?

A. It is a matter of transparency in public policy. The RES requirement is a mandate and the RES Adjustor clearly identifies the above-market component of the cost of this mandate. If above-market costs are shifted to base rates it would obscure the true costs of the RES requirement to the public, making these costs appear to be less than they actually are. This would not be good public policy. Moreover, the structure of cost recovery in the RES Tariff differs from that of base rates; notably, each customer class has a per-meter cap applicable to the RES Adjustor that limits the exposure of any individual customer to the above-market costs of the program. Shifting above-market costs into base rates undermines the protection otherwise afforded by the RES Adjustor caps.

Q. What is your recommendation to the Commission regarding the proper amount of post-test year solar generation costs that should be recovered in base rates?

A. I recommend that all costs in excess of the Market Cost of Comparable Conventional Generation be excluded from base rates. Prudently-incurred costs in excess of the Market Cost of Comparable Conventional Generation should remain subject to the RES Tariff and recovered through the RES Adjustor.

I present this adjustment in Attachment KCH-4. This adjustment reduces APS's proposed revenue requirement increase by **$9.928** million. Note that this adjustment is applied to the average-of-period value that I derived in my prior adjustment to post-test year plant additions. If my market cost adjustment were to be applied to the end-of-period value utilized by APS, the adjustment would be greater.

Q. In calculating the market cost adjustment, what portion of APS's solar generation revenue requirement did you determine to be in excess of the Market Cost of Comparable Conventional Generation?

A. Using APS's assumptions about the Market Cost of Comparable Conventional Generation for 2012, I determined that 64 percent of APS's solar generation revenue requirement is in excess of that level and should be excluded from base rates. This analysis is presented in Confidential Attachment KCH-4, page 4.

Q. What general representations has APS made with respect to the portion of its solar generation costs that it considers to be above the Market Cost of Comparable Conventional Generation?

A. In APS's Response to AECC 4.1.2(a), the Company indicates that on average, costs in excess of the market costs of generation for its AZ Sun plants represent 30 percent of project costs analyzed.

Q. Based on this response, we didn't you include 70 percent of APS's solar generation revenue requirement in base rates?

A. In reviewing the workpapers supporting APS's calculation, I determined that that 30 percent "above-market" calculation is based on comparing the long-term levelized cost of the solar plant additions to APS's projection of the long-term levelized Market Cost of Comparable Conventional Generation. While I have no objection to using the long-term levelized cost of the solar plant additions as the basis of the solar generation costs (doing so is more favorable to APS than using the current-year revenue requirement), I do not believe it is appropriate, for the purpose of determining the portion of costs included in test year base rates, to use a long-term levelized projection to represent the Market Cost of Comparable Conventional Generation.

Q. Why not?

A. The benchmark that delineates what today's customers pay in base rates should be today's Market Cost of Comparable Conventional Generation – not a blended value that is based on a projection of market costs over the next thirty-five years.

Needless to say, a projection of the Market Cost of Comparable Conventional Generation over a long-term requires assumptions about energy price and capacity cost escalation that is little more than speculation. But even if the future Market Cost of Comparable Conventional Generation was known with perfect certainty, today's base rates should be determined using current-day values. Customers should not pay rates based on thirty-five year projections of market prices.

Q. In offering your adjustment to base rates, are you recommending that APS cost recovery for the solar plant additions be denied?

A. No. I am simply making a recommendation regarding the appropriate recovery in base rates. To the extent that the cost in excess of the Market Cost of Comparable Conventional Generation is prudently-incurred, it should be eligible for recovery through the RES Adjustor.

SYSTEM BENEFITS CHARGE - NUCLEAR DECOMMISSIONING COSTS

Q. What is APS recommending with respect to the recovery of nuclear decommissioning costs?

A. APS has been granted approval by the Nuclear Regulatory Commission to extend the life of the Palo Verde Nuclear Generating Station ("PVNGS") by twenty years. This life extension through the 2045-47 time frame causes two fundamental impacts on the funds that must be accrued for the purpose of nuclear decommissioning: (1) it increases the total amount of money projected to be required to complete the decommissioning, due, in large part, to the expectation that decommissioning costs will be more expensive in the future because of inflation; and (2) it extends the time for contributions to be made to the sinking fund required to pay for the decommissioning, and similarly, extends the time that interest can be earned on the balance in the sinking fund. The net effect of these two impacts is that the annual contribution to the sinking fund necessary to pay for the decommissioning *decreases* significantly when the life of the facility is extended.

APS customers pay for decommissioning costs through the Systems Benefits Charge ("SBC"). According to Paragraph 11.4 of the 2009 Settlement Agreement, APS is required to seek to reduce its SBC by January 1, 2012 to reflect the reduced decommissioning costs attributable to the PVNGS life extension. The relevant language states:

> ...Pursuant to the terms of this Settlement, if and when license extension is granted, APS shall file with the Commission a revised nuclear decommissioning funding requirement and a commensurate downward adjustment to the decommissioning component of the Company's SBC and a reduction to the PSA as discussed above to be effective upon the later of the grant of license extension or January 1, 2012...

Largely consistent with this provision, on June 17, 2011, in Docket No. E-01345A-11-0247, APS filed an Application with the Commission to reduce the SBC by approximately $7.2 million per year, effective February 1, 2012. In addition, in this docket, APS has proposed a number of adjustments to the SBC that are unrelated to the PVGNS life extension. These APS adjustments are summarized on Attachment KCH-5, page 1, lines 8-11.

Q. Do you agree that $7.2 million is the appropriate reduction in the SBC associated with PVGNS life extension?

A. No. I believe the SBC should be reduced by an <u>additional</u> $8.704 million per year to better reflect the reduction in decommissioning costs associated with the PVNGS life extension.

Q. Please explain.

A. As shown in Attachment KCH-5, page 1, lines 9-10, APS's proposed $7.2 million reduction in the SBC that is related to PVNGS expenses is comprised of two components: a reduction in ISFSI expense of $4.236 million and a reduction in PVNGS decommissioning expense of $2.947 million. These two adjustments sum to $7.183 million.[24]

According to APS witness Jason C. La Benz, the going-forward annual decommissioning expense for all three PVNGS units – taking account of the life extension – is $17.249 million per year.[25] The ACC jurisdictional portion of this is $16.830 million. However, according to APS's workpapers, *prior to life extension*, the pro forma annual decommissioning expense for 2011 is just $15.630 million (jurisdictional).[26] The implication here is that the nuclear decommissioning costs that APS is seeking to recover from customers *post*-life extension appears to be greater than it would have been *absent* life extension.

The answer to this seeming paradox is revealed when we examine the PVNGS decommissioning costs that APS is seeking to recover from customers on a unit by unit basis.

In the case of PVNGS 1, because of the life extension, the annual nuclear decommissioning trust fund expense is reduced from $4.558 million to $0.449 million (total Company).[27] This reduction makes sense, in that it is consistent with my observation above that the annual contribution to the sinking fund necessary to pay for the decommissioning decreases significantly when the life of the facility is extended.

[24] See also direct testimony of Jason C. La Benz, p. 22, line 17. Note that ISFSI stands for "independent spent fuel storage installation."
[25] Ibid., p. 22, line 16.
[26] Source: JCL WP 22, p. 4.
[27] Source: Ibid.

For PVNGS 3, the annual nuclear decommissioning trust fund expense is reduced from \$5.414 million to \$1.832 million (total Company) due to life extension.[28] This reduction also makes sense.

However, in the case of PVNGS Unit 2, APS is actually recommending a significant *increase* in the annual decommissioning expense: from \$6.047 million (pre-life-extension) to \$14.968 million (post-life-extension, total Company).[29] The reason for this counter-intuitive jump in decommissioning expense for PVNGS Unit 2 involves the terms of a sale/leaseback transaction that APS entered for that unit, which, according to APS, *requires all decommissioning costs to be paid in full by 2015.* In other words, according to the terms of the sale/leaseback agreement, the incremental projected decommissioning cost associated with the life extension – needed to address costs starting in 2045 – must be fully funded by 2015. So rather than experiencing a *reduction* in annual decommissioning expense comparable to that of PVNGS 1 and 3, the annual nuclear decommissioning expense for PVNGS 2 actually increases by \$8.9 million. The jurisdictional share of this increase is \$8.7 million.

In my opinion, it is not reasonable for today's APS customers to bear this level of decommissioning expense for PVNGS 2. The life extension will provide benefits to customers for another thirty years beyond 2015. The decommissioning costs paid by APS customers should correspond to the remaining life of the unit.

Q. What is your recommendation to the Commission?

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[28] Source: Ibid.
[29] Source: Ibid.

A. Although a reasonable case can be made to reduce the annual decommissioning expense charged to APS customers for PVNGS 2 to levels comparable to PVNGS 1 and 3, I am recommending that the decommissioning expense charged to customers for PVNGS 2 merely be rolled back to the pre-life-extension annual expense of $6.047 million (total Company). Such an adjustment, although it would not pass on any decommissioning benefits associated with the life extension of PVNGS 2 at this time, would at least hold today's customers harmless from it. This level of expense in rates should remain in place until the 2015 expiration of the sale/leaseback terms, at which time it should be reset to assure full recovery from customers of the remaining decommissioning obligation, plus reimbursement of any funding provided by APS between 2012 and 2015 to cover the gap between the funds provided by customers and the decommissioning funding requirements of the sale/leaseback transaction.

This adjustment reduces the SBC charge by **$8.704** million, which is the jurisdictional share of the difference between the $6.047 million pre-life-extension decommissioning expense for PVNGS 2 and the $14.968 million post-life-extension expense. This adjustment is shown in Attachment KCH-5, page 1, line 14. The impact on the SBC unit cost is shown in Attachment KCH-5, page 2.

PROPOSED CHANGES TO THE 90/10 SHARING PROVISION IN THE PSA

Q. What is the 90/10 sharing provision in the PSA?

A. APS's Base Fuel Rate is established in a general rate case. The PSA is a mechanism by which deviations from the Base Fuel Rate are either recovered from or credited to customers in between rate cases. For most PSA items, 90 percent of the recovery or credit is allocated to customers and 10 percent is allocated to APS. The 90/10 sharing provision has been part of the PSA since the PSA was adopted in 2005. The adoption of the PSA was pursuant to a Settlement Agreement (to which AECC was a party) that was approved, with modifications, by the Commission in Decision No. 67744.

Q. What is APS's proposal with respect to the 90/10 sharing provision in the PSA?

A. As discussed in the direct testimony of APS witness Peter M. Ewen, APS is proposing to eliminate the 90/10 sharing provision. This change would place 100 percent of the risk from deviations in power supply costs on customers.

Q. What is APS's justification for this proposed change?

A. Mr. Ewen cites to three principal reasons: (1) APS is the only Arizona utility to have a 90/10 sharing mechanism; (2) fuel and purchased power prices are outside APS's control, and therefore, the 10 percent utility sharing acts only as a penalty or windfall; and (3) eliminating the 90/10 sharing provision will facilitate the resetting of fuel rates without controversy.

Q. Do you agree with APS's proposal?

A. No, I do not. In my opinion, eliminating the sharing provision would be a mistake. It is essential to keep customer and Company interests aligned by retaining an equitable sharing mechanism between customers and APS in the PSA.

APS's proposal fails to properly align customer and Company interests or to equitably share risks. Instead, under the Company's proposal, the PSA would simply pass through 100 percent of changes in Base Fuel Rates in between rate cases to customers. This type of 100 percent cost pass-through seriously reduces APS's incentive to manage its fuel and purchased power costs as well as it would manage them if the Company remained exposed to the energy cost risk. It is axiomatic that when a firm stands to gain or lose from its cost management decisions, as APS does today, the pursuit of its economic self-interest gives it a powerful incentive to perform well in managing its costs. I strongly recommend against adoption of a PSA design that removes this natural economic incentive.

Q. But aren't energy costs largely outside a utility's control?

A. Absolutely not. The utility's energy costs are completely out of the customers' control, but not of the utility. Utilities are not mere passive bystanders when it comes to managing power costs. Every hour of every day, utilities need to be managing the dispatch of their systems to achieve minimum costs, subject to the reliability constraints under which they operate. This requires a sophisticated approach to managing utility-owned resources, as well as conducting a large volume of transactions – purchases and sales – throughout the year. The depth and breadth of this around-the-clock dispatch and balancing requirement is so extensive that it is inadvisable for regulators to rely solely on after-the-fact prudence audits to ensure sound utility cost-management performance; rather it is far preferable for the Commission to harness the natural economic self-interest of the company to incentivize the desired behavior of ensuring sound utility cost-management performance.

Q. Are there other aspects of managing fuel and purchased power costs that are important besides optimizing system dispatch?

A. Yes. In addition to hourly dispatch, APS enters into numerous transactions throughout the course of the year that impact its fuel and purchased power costs, such as short- and long-term purchases and sales and fuel procurement. For example, APS transacted for more than 6.8 billion kilowatt-hours of long-term, intermediate-term, and short-term power purchases in 2010, valued at over $317 million, consummated with more than 90 counterparties. The Company also made over 4.1 billion kilowatt-hours of long-term, intermediate term, and short-term sales in 2010, worth more than $210 million, also transacted with more than 90 counterparties.[30] It is critical that APS have the proper incentives for these transactions to produce the greatest possible net benefit to customers. This incentive is most efficiently implemented by a regime in which APS shares in the benefits and risks of its decisions.

In addition to creating the proper incentives for APS's interactions with other parties, incentives play an important role with respect to the Company's own operations. For example, it is important for APS to schedule plant maintenance in a manner that takes into account the impact on fuel costs, e.g., by avoiding outages when replacement power is likely to be most expensive. Under the current PSA, the benefits and costs of deviations from the Base Fuel Rate are partially absorbed by APS; thus, currently, the Company has the incentive to take proper account of fuel costs when scheduling outages. However, a regime in which 100 percent of Base Fuel Rate deviations are passed through to customers removes the Company's natural economic incentive to properly consider the impact on fuel costs in its operations.

[30] Source: APS FERC Form 1, pp. 310-11; 326-27.

Q. Does APS hedge a portion of its fuel and purchased power costs?

A. Yes. When a utility hedges its fuel and/or purchased power costs, it is effectively locking in the cost of fuel and/or purchased power that is expected to be consumed in the future. According to information filed by APS in Docket No. E-01345A-09, APS hedges its fuel and purchased power cost on a rolling three-year forward basis. Approximately 85 percent of APS's price risk is hedged in year one; 50 to 60 percent is hedged in year two; and 30 to 40 percent is hedged in year three. To execute these hedges, APS uses a combination of exchange-traded futures and financial over-the-counter market products.

So while APS may be able to argue that it does not control the market price of natural gas, it is nevertheless the case that the Company's *decisions* in executing its natural gas hedging strategy (e.g., timing, magnitude) have a large influence on the cost of gas that APS ultimately incurs and the fuel costs that are passed on to customers.

Q. If APS locks in forward fuel prices at prices that later decline, how are these costs treated for ratemaking purposes?

A. In a general rate case, if the hedged price exceeds the projected market price, the difference is included as a component of fuel cost for full recovery from customers, subject only to prudency considerations. Conversely, if the hedged price is below the projected market price, this difference is credited against the fuel cost recovered from customers.

In between rate cases, these differences are included in the PSA, subject to the 90/10 sharing.

Q. What natural gas hedging costs are included for recovery in this general rate case?

A. In this case, APS is seeking to recover approximately $70 million in gas hedge liquidation costs; that is, APS's hedges cost $70 million more than the projected cost of natural gas in 2012. This $70 million cost constitutes approximately 25 percent of APS's projected $273 million of natural gas costs in this case.

Q. How would APS's proposal to eliminate the 90/10 sharing affect the sharing of risks related to APS's hedging decisions?

A. Under the current PSA, if APS's hedges turn out to cost more than was projected at the time of the general rate case, the Company shares in this cost; similarly, if the Company's hedging decisions prove to reduce fuel costs below what was projected in the general rate case, APS shares in this gain.

Under APS's proposal to eliminate the sharing mechanism, there would be no risk whatsoever to APS from its hedging decisions: short of a prudency disallowance, 100 percent of the risk from APS's hedging decisions would be borne by customers.

Q. Do you believe that the threat of a prudency disallowance is sufficient incentive to fully align utility and customer interests in managing fuel costs in between rate cases?

A. No. In my view, the threat of a finding of imprudence following an after-the-fact audit is not a good substitute for a utility having "skin in the game" when it comes to managing its fuel costs. A finding of imprudence essentially requires a determination that a utility acted <u>unreasonably</u> in its power cost management.

In contrast, a risk-sharing mechanism structured such that each and every transaction affects the Company's bottom line, provides an incentive for the Company to get the *best possible deal* from every transaction. Striving to get the best possible deal from every transaction is different from simply not behaving unreasonably. Getting the best possible deal is a more exacting and efficient aspiration. A well-crafted sharing mechanism supports this objective.

Q. In the past year, have other utility commissions in the Western United States considered the question of requiring a sharing mechanism in a power supply adjustor mechanism?

A. Yes. In the past year, both the Wyoming and Utah commissions considered whether to adopt a sharing mechanism for a power cost adjustor mechanism.

Q. Are you personally familiar with these two cases?

A. Yes. I was a witness in both cases.

Q. What determinations did the Wyoming and Utah commissions reach?

A. The Wyoming and Utah commissions each independently determined to adopt 70/30 sharing mechanisms, with 70 percent of the deviations in base fuel costs being assigned to customers and 30 percent assigned to the utility.[31]

Q. In your opinion, does the 70/30 sharing arrangements adopted by the Wyoming and Utah commissions strike a reasonable balance between utility and customer interests?

[31] Wyoming Public Service Commission Memorandum Opinion, Findings and Order, February 4, 2011, issued in Docket No. 20000-368-EA-10.
Utah Public Service Commission, Corrected Report and Order, March 3, 2011, issued in Docket No. 09-035-15.

A. Yes, it does. This sharing ratio places the substantial majority of responsibility for recovering base fuel cost deviations on customers, but it meaningfully aligns utility and customer interests through shared benefits and costs.

Q. Should this Commission consider adopting the 70/30 sharing provision recently adopted in Wyoming and Utah?

A. Yes. If the Commission is interested in revisiting the question of the appropriate sharing proportions in the PSA, then I strongly encourage the Commission to consider adopting the 70/30 sharing proportion that was recently approved in these other two Western states, rather than the 100/0 approach advocated by APS, which is a movement in the entirely wrong direction.

Q. What is your response to Mr. Ewen's observation that APS is the only Arizona utility to have a 90/10 sharing mechanism?

A. It is correct that TEP has a PSA-type adjustor mechanism (Purchased Power and Fuel Adjustment Clause or "PPFAC") that assigns 100 percent of base fuel cost deviations to customers. However, the facts surrounding the adoption of this mechanism for TEP are very different from those of APS. The TEP PPFAC was adopted as part of a comprehensive settlement agreement in 2008 following the expiration of the TEP rate freeze that had been in effect since a prior 1999 Settlement Agreement. As such, the structure of the TEP PPFAC that was negotiated was but one piece of a large and interrelated package.

Q. Where you directly involved in the negotiation of the 2008 TEP Settlement Agreement?

A. Yes, I was.

Q. What facts surrounding the adoption of the TEP PPFAC as part of a comprehensive settlement agreement are particularly noteworthy?

A. At least two facts are particularly noteworthy that distinguish TEP's situation from APS's situation. First, the 2008 TEP Settlement Agreement that adopted the PPFAC without a sharing provision also adopted a four-year freeze in base rates. This base rate freeze was all the more noteworthy in that it followed a prior freeze in TEP's rates that had extended over nine years, spanning 1999 to 2008, that had resulted from a previous settlement agreement in 1999. The long-term base rate stability that was achieved as part of the 2008 TEP Settlement Agreement was an important factor in justifying the absence of a sharing mechanism in the PPFAC for the same time period.

Second, the order approving the 2008 Settlement Agreement also determined that millions of dollars of stranded cost overpayments by customers would be applied (with interest) as a credit to the initial PPFAC account. This amount was later determined to be $58.8 million.[32] In other words, by design, the first $58.8 million-plus of fuel costs that would otherwise have flowed through the TEP PPFAC was intended to be completely offset by this stranded cost credit. Consequently, even though the TEP PPFAC has been on the books since 2009 – the actual PPFAC charge to customers has yet to be anything but zero. This is a decidedly different set of circumstances than has been experienced with APS's PSA. The lack of a sharing mechanism in the TEP PPFAC should not be used as a precedent for eliminating this important provision in the APS PSA. The circumstances are not comparable.

[32] Decision No. 70958 at 2.

REVENUE DECOUPLING

Q. What is APS proposing with respect to revenue decoupling?

A. As described in the direct testimony of APS witness Leland Snook, APS is proposing to adopt a full revenue decoupling mechanism, as part of what APS terms its Energy and Infrastructure Account Adjustment ("EIA").

The EIA would apply to almost all metered retail customers, including the largest industrial customers. It would be designed to recover any differences between allowed non-fuel revenue-per-customer and actual non-fuel revenue-per-customer. The EIA charge (or credit) would be recovered through a percentage adjustor applied to all applicable rate schedules.

Q. Are you familiar with the Commission Policy Statements regarding decoupling that were issued December 29, 2010?

A. Yes, I am.

Q. Did AECC participate in the decoupling workshop process that was sponsored by the Commission in 2010?

A. Yes.

Q. What position regarding revenue decoupling did AECC advocate as part of the workshops?

A. AECC consistently recommended <u>against</u> adoption of a decoupling mechanism for <u>any customer class</u>. At the most fundamental level, decoupling is as much a "revenue assurance" mechanism as it is a "conservation enabling" mechanism. As such, it is sure to capture a much wider range of effects than just customer responses to utility-sponsored energy efficiency programs. For example, decoupling provides unwarranted insulation to the utility from the effects of price elasticity. Generally, all sellers of goods face a risk that price increases will reduce sales. But, with decoupling, if customers respond to utility rate hikes by reducing their electricity, fixed charges are increased to compensate the utility for any resultant reduction in per-customer usage. Such an increase reflects an undue transfer of risk from utilities to customers.

Further, to the extent that customers reduce usage in response to economic conditions or otherwise practice self-funded energy conservation, these behaviors will be captured in the decoupling adjustment and unduly increase rates to customers. In addition, decoupling as proposed by APS will also cause rates to be adjusted due to changes in weather-related usage.

Q. Do the Commission Policy Statements provide for any flexibility with respect to the treatment of customer classes?

A. Yes. Policy Statement 11 provides that:

> Broad participation in decoupling is preferred; however, the unique characteristics of each utility may merit different treatment of some customer classes. Utilities should address any proposed distinct treatments and justify why certain customer classes may merit different treatment.

Q. If decoupling is approved by the Commission for APS in this proceeding, are there customer classes that merit different treatment?

A. Yes. At a minimum, Rate Schedules 34 and 35 should be excluded from the EIA. Recall that the premise for decoupling is to insulate the utility from the loss of fixed-cost recovery when customers conserve energy by participating in utility-sponsored energy efficiency programs. This erosion of fixed-cost recovery may occur because, for many rate schedules, a portion of fixed cost is recovered through the volumetric energy charge. Thus, if energy consumption declines, all other things being equal, fixed cost recovery from conserving customers on these rate schedules declines.

However, this is not the case for Rate Schedules 34 and 35, which serve customers with billing demands of 3 MW or above. For these customers, a very large portion of the cost recovery occurs through a demand charge; very little – if any – fixed cost recovery occurs through the volumetric energy charge. In other words, the rate designs of these customer classes already insulate APS from the loss of fixed-cost recovery when these customers conserve energy.

For example, in the case of Rate Schedule 34, the proposed energy charge is 4.258 cents per kWh. If a Schedule 34 customer conserves energy, it will allow APS to reduce its most expensive dispatchable generation, which is typically natural gas. According to APS's filing in this case, the average fuel cost of its gas generation is 6.15 cents per kWh[33] – well above the Schedule 34 energy charge. In light of this price/cost relationship, it is clear that decoupling is not necessary to ensure that APS continues to recover its fixed cost from a Schedule 34 customer when a Schedule 34 customer conserves energy.

Rate Schedule 35 is a time-of-use rate for which the proposed energy charges range from 3.559 cents per kWh (off-peak) to 4.749 cents per kWh (on-peak). Thus, the same conclusion holds true: decoupling is not necessary to ensure that APS continues to recover its fixed cost from a Schedule 35 customer when a Schedule 35 customer conserves energy.

Q. Wouldn't energy conservation also enable a Schedule 34 or 35 customer to reduce its demand charge?

[33] APS Attachment PME-3, page 2 (Updated by APS Using 9/3/0/11 Prices)

A. It is much more difficult for a Schedule 34 or 35 customer to reduce its demand charge from conservation in the short term given the structure of APS's tariff. This is because the demand charges for Rate Schedules 34 and 35 are subject to an 80% ratchet. In APS's tariff, this ratchet means that the demand charge in any given month cannot fall below 80% of its peak level measured during the preceding six summer months. The upshot is that energy conservation for a Schedule 34 or 35 customer is much less likely to influence its demand-related charges than its energy-related charges. And as I have discussed, there is little or no fixed cost recovery in the Schedule 34 and 35 energy charges at the margin.

Q. In his direct testimony, APS witness Snook suggested that Schedule 34 and 35 customers might merit a ratemaking alternative to decoupling. Do you wish to respond?

A. Yes. Mr. Snook's testimony largely acknowledges the points I am making regarding Schedule 34 and 35 rate design. However, he indicates that to provide the insulation that APS is seeking, the demand ratchet for these customers might need to be increased up to 100 percent and/or the ratchet period extended from twelve to twenty-four months.

I disagree. A ratchet of 100 percent on generation demand charges is extreme. I am aware of no other utility in America with such a ratchet on generation demand. Indeed, a ratchet of 80 percent on generation demand is already extraordinarily high – and I am certain is among the highest in the country. The existing rate design for Rates 34 and 35 already insulates APS from erosion of fixed cost recovery attributable to energy conservation. There is no need to make the rate design more extreme just to satisfy APS's desire for revenue assurance.

Q. Are there other reasons for exempting certain customer classes from decoupling if decoupling is otherwise adopted?

A. Yes. Maintaining a constant "revenue per customer" or "fixed-cost recovery per customer" is not an appropriate rate design objective for classes of customers that have few customers, have heterogeneous populations, and/or whose class composition shows a wide range of usage levels, such as Rates 34/35 and the largest Rate 32 customers. The fixed-cost recovery per customer of these classes will be very sensitive to the *composition* of these customers; for example, the opening or closing of a copper mine would impact such a calculation without at all being representative of utility-sponsored conservation programs. In short, given the tremendous diversity among non-residential customers, attempting to attribute to utility-sponsored energy conservation projects changes in "average fixed-cost recovery per customer" of non-residential customers is meaningless. The concept of an "average" non-residential customer for this purpose is without merit as a ratemaking mechanism.

Changes in the overall economy are far more likely to influence fixed-cost recovery per customer for non-residential customers than energy conservation programs. Application of decoupling to these customers would result in undue changes in rates in response to factors that are unrelated to energy conservation. This would be particularly unfortunate since the primary objectives of decoupling can be accomplished for these customers through rate design, as discussed above.

Q. Is revenue decoupling commonplace among electric utilities in the Western United States?

A. No. Outside of California, I am not aware of electric decoupling regimes in place anywhere in the West except in the Portland General Electric and Idaho Power service territories. Notably, both of these utilities exclude larger customers from their decoupling mechanisms.

Q. What is your recommendation to the Commission on this issue?

A. I recommend that the Commission reject APS's decoupling proposal for all customers. If, however, some form of revenue decoupling is approved by the Commission, I recommend that customers with billing demands greater than 400 kW (i.e., Rates 32-L, 34, and 35) be excluded from the program. Rates 34 and 35 already have rate designs that insulate APS from loss of fixed-cost recovery from energy conservation. The design of Rate 32-L can be modified to achieve a comparable result.

Q. If larger customers are excluded from the decoupling mechanism, would other customers be forced to bear decoupling-related costs caused by the larger customers?

A. Absolutely not. If a customer group is excluded from the decoupling mechanism, they would neither pay the EIA *nor shift costs to the EIA for recovery*. The only decoupling costs that should be recorded by APS would be those directly attributable to the participating classes. Consequently, no costs would be shifted from non-participants to participants.

ENVIRONMENTAL AND RELIABILITY ACCOUNT

Q. What has APS proposed with respect to the adoption of an Environmental and *Reliability Account?*

A. As discussed by Mr. Snook, APS is proposing that the Commission approve an Environmental and Reliability Account ("ERA"). The ERA would allow APS to pass through to customers the carrying costs of environmental improvement projects and generation plant capacity acquisition and additions. The carrying costs would consist of a return on ERA-qualified investments at APS's most-recently-approved weighted average cost of capital; depreciation expense; income taxes; property taxes; deferred taxes and tax credits (where appropriate); and operations and maintenance expense. The ERA would be reset each year.

Q. Do you support adoption of the proposed ERA?

A. No. If adopted, the ERA would be a vehicle for potentially flowing through hundreds of millions of dollars of costs to APS customers without the scrutiny of a rate case. It is an example of unwarranted single-issue ratemaking.

Q. What is single-issue ratemaking?

A. Single-issue ratemaking occurs when utility rates are adjusted in response to a change in cost or revenue items considered in isolation. Single-issue ratemaking ignores the multitude of other factors that otherwise influence rates, some of which could, if properly considered, move rates in the opposite direction from the single-issue change.

When regulatory commissions determine the appropriateness of a rate or charge that a utility seeks to impose on its customers the standard practice is to review and consider all relevant factors, rather than just certain factors in isolation. Considering some costs or revenues in isolation might cause a commission to allow a utility to increase rates to recover higher costs in one area without recognizing counterbalancing savings in another area. For example, the proposed ERA would allow APS to earn a return on its new investment and charge customers for depreciation expenses associated with that new investment without recognizing that its existing rate base would have depreciated to a lower value at the time the ERA is charged to customers. In short, it exacerbates the problems associated with APS's practice of seeking to set rates using unsynchronized test periods. In my opinion, the proposed ERA is a classic example of an application of single-issue ratemaking that is not in the public interest. The Commission should view such proposals with great wariness. I recommend that it be rejected.

Q. Are you aware of any other utilities in the western United States that have such an adjustment mechanism in place?

A. No. I have researched the tariffs of the major investor-owned utilities in the western United States. While California utilities have "attrition adjustments," I am not aware of any utility in the West that has in place the type of adjustment mechanism that APS is seeking.

Q. Does this conclude your direct testimony?

A. Yes, it does.

APPENDIX A

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Vitae

PROFESSIONAL EXPERIENCE

Principal, Energy Strategies, L.L.C., Salt Lake City, Utah, January 2000 to present. Responsible for energy-related economic and policy analysis, regulatory intervention, and strategic negotiation on behalf of industrial, commercial, and public sector interests. Previously Senior Associate, February 1995 to December 1999.

Adjunct Instructor in Economics, Westminster College, Salt Lake City, Utah, September 1981 to May 1982; September 1987 to May 1995. Taught in the economics and M.B.A. programs. Awarded Adjunct Professor of the Year, Gore School of Business, 1990-91.

Chief of Staff to the Chairman, Salt Lake County Board of Commissioners, Salt Lake City, Utah, January 1991 to January 1995. Senior executive responsibility for all matters of county government, including formulation and execution of public policy, delivery of approximately 140 government services, budget adoption and fiscal management (over $300 million), strategic planning, coordination with elected officials, and communication with consultants and media.

Assistant Director, Utah Energy Office, Utah Department of Natural Resources, Salt Lake City, Utah, August 1985 to January 1991. Directed the agency's resource development section, which provided energy policy analysis to the Governor, implemented state energy development policy, coordinated state energy data collection and dissemination, and managed energy technology demonstration programs. Position responsibilities included policy formulation and implementation, design and administration of energy technology demonstration programs, strategic management of the agency's interventions before the Utah Public Service Commission, budget preparation, and staff development. Supervised a staff of economists, engineers, and policy analysts, and served as lead economist on selected projects.

Utility Economist, Utah Energy Office, January 1985 to August 1985. Provided policy and economic analysis pertaining to energy conservation and resource development, with an emphasis on utility issues. Testified before the state Public Service Commission as an expert witness in cases related to the above.

Acting Assistant Director, Utah Energy Office, June 1984 to January 1985. Same responsibilities as Assistant Director identified above.

Research Economist, Utah Energy Office, October 1983 to June 1984. Provided economic analysis pertaining to renewable energy resource development and utility issues. Experience includes preparation of testimony, development of strategy, and appearance as an expert witness for the Energy Office before the Utah PSC.

Operations Research Assistant, Corporate Modeling and Operations Research Department, Utah Power and Light Company, Salt Lake City, Utah, May 1983 to September 1983. Primary area of responsibility: designing and conducting energy load forecasts.

Instructor in Economics, University of Utah, Salt Lake City, Utah, January 1982 to April 1983. Taught intermediate microeconomics, principles of macroeconomics, and economics as a social science.

Teacher, Vernon-Verona-Sherrill School District, Verona, New York, September 1976 to June 1978.

EDUCATION

Ph.D. Candidate, Economics, University of Utah (coursework and field exams completed, 1981).

> Fields of Specialization: Public Finance, Urban and Regional Economics, Economic Development, International Economics, History of Economic Doctrines.

Bachelor of Science, Education, State University of New York at Plattsburgh, 1976 (cum laude).

Danish International Studies Program, University of Copenhagen, 1975.

SCHOLARSHIPS AND FELLOWSHIPS

University Research Fellow, University of Utah, Salt Lake City, Utah 1982 to 1983.
Research Fellow, Institute of Human Resources Management, University of Utah, 1980 to 1982.
Teaching Fellow, Economics Department, University of Utah, 1978 to 1980.
New York State Regents Scholar, 1972 to 1976.

EXPERT TESTIMONY

"In the Matter of the Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina," **North Carolina** Utilities Commission, Docket No. E-7, Sub 989. Direct testimony submitted October 31, 2011.

"In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan," Public Utilities Commission of **Ohio**," Case Nos. 11-346-EL-SSO and 11-348-EL-SSO, et al. Direct testimony in support of Stipulation submitted October 28, 2011.

"Application of Nevada Power Company d/b/a NV Energy, for Authority to Increase Its Annual Revenue Requirement for General Rates Charged to All Classes of Customers, Begin to Recover the Costs of Constructing Harry Allen Combined Cycle, Goodsprings and Other Generating, Transmission and Distribution Plant Additions, and to Reflect Changes in Cost of Service and for Relief Properly Thereto; Application of Nevada Power Company d/b/a/ NV Energy for Approval of New and Revised Depreciation Rates for Its Electrical Operations; Application of Sierra Pacific Power Company d/b/a/ NV Energy for a Determination of the Reasonableness of the Ely Energy Center Project Development Costs and for Authority to Reclassify Those Costs from a Deferred Debit to a Regulatory Asset with an Appropriate Carrying Charge," Public Utilities Commission of **Nevada**, Docket Nos. 11-06006, 11-06007, and 11-06008. Direct testimony submitted October 12, 2011. Cross examined November 2, 2011.

"In the Matter of the Application of Idaho Power Company for Authority to Increase Its Rates and Charges for Electric Service in Idaho," **Idaho** Public Utilities Commission, Case No. IPC-E-11-08. Direct testimony submitted October 7, 2011. Rebuttal testimony submitted November 16, 2011.

"In the Matter of the Application of Public Service Company of Colorado for an Order Approving Regulatory Treatment of Margins Earned from Certain Renewable Energy Credit and Energy Transactions and Petition for Declaratory Order Clarifying the Meaning of the Phrase) "Transactions Executed" as that Phrase Is Used in the Settlement Agreement Approved in Docket No. 09A-602E," **Colorado** Public Utilities Commission, Docket No. 11A-510E. Answer testimony submitted September 19, 2011. Cross examined October 20, 2011.

"In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan," Public Utilities Commission of **Ohio**," Case Nos. 11-346-EL-SSO and Case No. 11-348-EL-SSO. "In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain

Accounting Authority," Case Nos. 11-349-EL-AAM and 11-350-EL-AAM. Direct testimony submitted July 25, 2011.

"In the Matter of the Application of Appalachian Power Company for an Adjustment of Electric Base Rates," **Virginia** Corporation Commission, Case No. PUE-2011-00037. Direct testimony submitted July 20, 2011.

"Ameren Illinois Company d/b/a Ameren Illinois, Proposed General Increase in Electric Delivery Service Rates; Ameren Illinois Company d/b/a Ameren Illinois, Proposed General Increase in Natural Gas Rates," **Illinois** Commerce Commission, Docket Nos. 11-0279 and 11-0282. Direct testimony submitted June 29, 2011. Rebuttal testimony submitted August 23, 2011.

"In the Matter of PacifiCorp, dba Pacific Power 2012 Transition Adjustment Mechanism," Public Utility Commission of **Oregon**, Docket No. UE-227. Reply testimony submitted June 24, 2011. Rebuttal testimony submitted August 16, 2011.

"In the Matter of the Application of Rocky Mountain Power to Implement a Permanent Avoided Cost Methodology for Customers That Do Not Qualify for Tariff Schedule 37 – Avoided Cost Purchases from Qualifying Facilities," **Wyoming** Public Service Commission, Docket No. 20000-388-EA-11. Direct testimony submitted May 26, 2011. Cross examined August 2, 2011.

"In the Matter of the Application of Public Service Company of New Mexico for Revision of Its Retail Electric Rates Pursuant to Advice Notice Nos. 397 and 32 (Former TNMP Services), Public Service Company of New Mexico, Applicant," **New Mexico** Public Regulation Commission, Case No. 10-00086-UT. Direct testimony in Opposition to Stipulation submitted April 14, 2011. Cross examined May 12, 2011.

"In the Matter of the Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Utility Service Rates in Wyoming Approximately $97.9 Million Per Year or 17.3 Percent," **Wyoming** Public Service Commission, Docket No. 20000-384-ER-10. Direct testimony submitted April 11, 2011. Cross answer testimony submitted May 6, 2011. Stipulation testimony submitted June 9, 2011. Cross examined June 20, 2011.

"In the Matter of the Application of Rocky Mountain Power for Approval of an Adjustment to the Demand-Side Management Program and Suspend Schedule 191 Rate Surcharges," **Wyoming** Public Service Commission, Docket No. 20000-383-ER-10. Direct testimony submitted March 30, 2011. Cross examined May 11, 2011.

"In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations," **Utah** Public Service Commission, Docket No. 10-035-124. Direct testimony submitted March 9, 2011 (test period); May 26, 2011 (revenue requirement); and June 2, 2011 (cost of service). Rebuttal testimony submitted March 17, 2011 (test period) and June 30, 2011 (revenue requirement). Surrebuttal testimony submitted July 19, 2011 (revenue requirement). Cross examined March 24, 2011 (test period); August 3, 2011 (revenue requirement stipulation); and August 8, 2011 (cost of service stipulation).

"Application of Nevada Power Company d/b/a NV Energy to Establish Interim Base Energy Efficiency Program Rates and Base Energy Efficiency Implementation Rates Pursuant To NRS 704.785 and the Order Issued in Docket No. 09-07016; Application of Sierra Pacific Power Company d/b/a NV Energy to Establish Interim Base Energy Efficiency Program Rates and Base Energy Efficiency Implementation Rates Pursuant to NRS704.785 and the Order Issued in Docket No. 09-07016," Public Utilities Commission of **Nevada,** Docket Nos. 10-10024 and 10-10025. Direct testimony submitted March 8, 2011. Cross examined March 29, 2011.

"2010 Puget Sound Energy Tariff Filing," **Washington** Utilities and Transportation Commission, Docket No. UG-101644. Joint testimony in support of stipulation filed February 11, 2011. Oral testimony in support of stipulation presented March 1, 2011.

"Petition of Duke Energy Indiana, Inc. for Approval to Offer Additional Energy Efficiency Programs; For Approval of Program Cost Recovery, Lost Revenues and Incentives Pursuant to 170 IAC 4-8-5, 170 IAC 4-8-6, and 170 IAC 4-8-7; Authority to Defer Costs Pending Approval and for Authority to Implement Annual Tracking Mechanism," **Indiana** Utility Regulatory Commission, Cause No. 43955. Direct testimony submitted February 9, 2011.

"In the Matter of the Application of Duke Energy Ohio for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications, and Tariffs for Generation Service," Public Utilities Commission of **Ohio**, Case No. 10-2586-EL-SSO. Direct testimony submitted December 21, 2010. Deposed December 22, 2010. Cross examined January 18, 2011.

"In the Matter of the Application of Public Service Company of Colorado for Approval of a Number of Strategic Issues Relating To Its DSM Plan, Including Long-Term Electric Energy Savings Goals and Incentives," **Colorado** Public Utilities Commission, Docket No. 10A-554EG. Answer testimony submitted December 17, 2010. Cross answer testimony submitted February 4, 2011. Cross examined March 2, 2011.

"In the Matter of Appalachian Power Company and Wheeling Power Company," Public Service Commission of **West Virginia**, Case No. 10-0699-E-42T. Direct testimony submitted November 10, 2010. Rebuttal testimony submitted November 23, 2010.

"In the Matter of the Application of Rocky Mountain Power for Alternative Cost Recovery for Major Plant Additions of the Populus to Ben Lomond Transmission Line and Dunlap I Wind Project," **Utah** Public Service Commission, Docket No. 10-035-89. Confidential direct testimony submitted October 26, 2010. Oral testimony in support of stipulation presented December 6, 2010.

"In the Matter of Georgia Power Company's 2010 Rate Case," **Georgia** Public Service Commission, Docket No. 31958. Direct testimony submitted October 22, 2010. Cross examined November 8, 2010.

"In the Matter of the Application of Rocky Mountain Power for Authority to Implement an Energy Cost Adjustment Mechanism," **Wyoming** Public Service Commission, Docket No. 20000-368-EA-10. Direct testimony submitted September 10, 2010. Cross examined November 9, 2010.

"Application of Entergy Texas, Inc. for Authority to Change Rates and Reconcile Fuel Costs," Public Utility Commission of **Texas**, Docket No. 37744. Direct testimony submitted June 9, 2010.

"Portland General Electric General Rate Case Filing," Public Utility Commission of **Oregon**, Docket No. UE-215. Opening testimony submitted June 4, 2010. Joint testimony in support of stipulation submitted August 2, 2010.

"In the Matter of the Application of Duke Energy Ohio, Inc. to Establish and Adjust the Initial Level of its Distribution Reliability Rider," Public Utilities Commission of **Ohio**, Case No. 09-1946-EL-RDR. Direct testimony submitted May 18, 2010.

"In the Matter of PacifiCorp, dba Pacific Power, 2011 Transition Adjustment Mechanism," Public Utility Commission of **Oregon**, Docket No. UE-216. Reply testimony submitted May 12, 2010. Joint testimony in support of stipulation submitted July 26, 2010.

"In the Matter of the Application of Rocky Mountain Power for Alternative Cost Recovery for Major Plant Additions of the Ben Lomond to Terminal Transmission Line and the Dave Johnston Generation Unit 3 Emissions Control Measure," **Utah** Public Service Commission, Docket No. 10-035-13. Direct testimony submitted April 26, 2010.

"In the Matter of a Notice of Inquiry into Energy Efficiency," **Arkansas** Public Service Commission, Docket No. 10-010-U. Direct testimony submitted March 23, 2010. Cross examined October 18, 2010.

"In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service," **Arkansas** Public Service Commission," Docket No. 09-084-U. Direct testimony submitted February 26, 2010.

"In the Matter of the Application of Rocky Mountain Power for Approval of a General Rate

Increase of Approximately $70.9 Million per Year or 13.7 Percent," **Wyoming** Public Service Commission, Docket No. 20000-352-ER-09. Direct testimony submitted February 16, 2010. Cross answer testimony submitted March 15, 2010. Direct settlement testimony submitted March 31, 2010. Cross examined April 23, 2010.

"Amended Petition of Puget Sound Energy, Inc., for an Order Authorizing the Use of the Proceeds from the Sale of Renewable Energy Credits and Carbon Financial Instruments," **Washington** Utilities and Transportation Commission, Docket No. UE-070725. Response testimony submitted January 28, 2010.

"Application of Appalachian Power Company for a 2009 Statutory Review of Rates Pursuant to § 56.585.1 A of the Code of Virginia," **Virginia** Corporation Commission, Case No. PUE-2009-00030. Direct testimony submitted December 28, 2009. Additional direct testimony submitted March 8, 2010. Cross examined April 1, 2010.

"In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications with Reconciliation Mechanism and Tariffs for Generation Service," Public Utilities Commission of **Ohio**, Case No. 09-906-EL-SSO. Direct testimony submitted December 4, 2009. Deposed December 10, 2009.

"2009 Puget Sound Energy General Rate Case," **Washington** Utilities and Transportation Commission, Docket Nos. UE-090704 and UG-090705. Response testimony submitted November 17, 2009. Joint testimony in support of stipulation submitted January 8, 2010.

"In the Matter of the Application of Rocky Mountain Power for Approval of Its Proposed Energy Cost Adjustment Mechanism," **Utah** Public Service Commission, Docket No. 09-035-15. Direct Phase I testimony submitted November 16, 2009. Direct Phase II testimony submitted August 4, 2010. Rebuttal Phase II testimony submitted September 15, 2010. Surrebuttal Phase I testimony submitted January 5, 2010. Surrebuttal Phase II testimony submitted October 13, 2010. Cross examined January 12, 2010 (Phase I) and November 2, 2010 (Phase II).

"In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of Its Proposed Electric Service Schedules and Electric Service Regulations," **Utah** Public Service Commission, Docket No. 09-035-23. Direct testimony submitted October 8, 2009. Rebuttal testimony submitted November 12, 2009. Surrebuttal testimony submitted November 30, 2009. Cross examined December 15-16, 2009.

"Re: The Tariff Sheets Filed by Public Service Company of Colorado with Advice Letter No. 1535 – Electric," **Colorado** Public Utilities Commission, Docket No. 09AL-299E. Answer testimony submitted October 2, 2009. Surrebuttal testimony submitted December 18, 2009.

"In the Matter of the Applications of Westar Energy, Inc., and Kansas Gas and Electric Company for Approval to Make Certain Changes in their Charges for Electric Service," **Kansas** Corporation Commission, Docket No. 09-WSEE-925-RTS. Direct testimony submitted September 30, 2009. Cross answer testimony submitted October 16, 2009.

"Central Illinois Light Company d/b/a AmerenCILCO Proposed General Increase in Electric Delivery Service Rates; Central Illinois Public Service Company d/b/a AmerenCIPS Proposed General Increase in Electric Delivery Service Rates; Illinois Power Company d/b/a/ AmerenIP Proposed General Increase in Electric Delivery Service Rates; Central Illinois Light Company d/b/a AmerenCILCO Proposed General Increase in Gas Delivery Service Rates; Central Illinois Public Service Company d/b/a AmerenCIPS Proposed General Increase in Gas Delivery Service Rates; Illinois Power Company d/b/a/ AmerenIP Proposed General Increase in Gas Delivery Service Rates," **Illinois** Commerce Commission, Docket Nos. 09-0306, 09-0307, 09-0308, 09-0309, 09-0310, and 09-0311. Direct testimony submitted September 28, 2009. Rebuttal testimony submitted November 20, 2009.

"In the Matter of the Complaint of Nucor Steel-Indiana, a Division of Nucor Corporation against Duke Energy Indiana, Inc. for Determination of Reasonable and Just Charges and Conditions for Electric Service and Request for Expedited Adjudication," **Indiana** Utility Regulatory Commission, Cause No. 43754. Direct testimony submitted September18, 2009. Rebuttal testimony submitted December 3, 2009. Testimony withdrawn pursuant to settlement agreement.

"In the Matter of PacifiCorp's Filing of Revised Tariff Schedules for Electric Service in Oregon," Public Utility Commission of **Oregon,** Docket No. UE-210. Reply testimony submitted July 24, 2009. Joint testimony in support of stipulation submitted September 25, 2009.

"In The Matter of the Application of Rocky Mountain Power to Establish an Avoided Cost Methodology for Customers That Do Not Qualify for Tariff Schedule 37 – Avoided Cost Purchases from Qualifying Facilities," **Wyoming** Public Service Commission, Docket No. 20000-342-EA-09. Direct testimony submitted July 21, 2009. Cross examined September 1, 2009.

"In the Matter of PacifiCorp, dba Pacific Power, 2010 Transition Adjustment Mechanism," Public Utility Commission of **Oregon,** Docket No. UE-207. Reply testimony submitted July 14, 2009. Joint testimony in support of stipulation submitted September 25, 2009.

"In The Matter of the Application of The Detroit Edison Company for Authority to Increase Its Rates, Amend Its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy,"

Michigan Public Service Commission, Case No. U-15768. Direct testimony submitted July 9, 2009. Rebuttal testimony submitted July 30, 2009.

"In the Matter of the Investigation of Westar Energy, Inc., and Kansas Gas and Electric Company to Consider the Issue of Rate Consolidation and Resulting Rate Design," **Kansas** Corporation Commission," Docket No. 09-WSEE-641-GIE. Direct testimony submitted June 26, 2009. Cross examined August 17, 2009.

"Illinois Commerce Commission on Its Own Motion vs Commonwealth Edison Company, Investigation of Rate Design Pursuant to Section 9-250 of the Public Utilities Act," **Illinois** Commerce Commission, Docket No. 08-0532. Direct testimony submitted May 22, 2009.

"In the Matter of the Application of Duke Energy Kentucky, Inc. for Approval of Energy Efficiency Plan, Including an Energy Efficiency Rider and Portfolio of Energy Efficiency Programs," **Kentucky** Public Service Commission, Case No. 2008-00495. Direct testimony submitted May 11, 2009.

"In the Matter of the Application by Nevada Power Company d/b/a NV Energy, filed Pursuant to NRS§704.110(3) and NRS §704.110(4) for Authority to Increase Its Annual Revenue Requirement for General Rates Charged to All Classes of Customers, Begin to Recover the Costs of Acquiring the Bighorn Power Plant, Constructing the Clark Peakers, Environmental Retrofits and Other Generating, Transmission and Distribution Plant Additions, to Reflect Changes in Cost of Service and for Relief Properly Related Thereto, Public Utilities Commission of **Nevada**, Docket No. 08-12002. Direct testimony submitted April 14, 2009 (revenue requirement) and April 21, 2009 (cost of service/rate design). Cross examined May 6, 2009.

"Verified Petition of Duke Energy Indiana, Inc. Requesting the Indiana Utility Regulatory Commission to Approve an Alternative Regulatory Plan Pursuant to the Ind. Code 8-1-2.5, *Et Seq.*, for the Implementation of an Electric Distribution System "SmartGrid" and Advanced Metering Infrastructure, Distribution Automation Investments, and a Distribution Renewable Generation Demonstration Project and Associated Accounting and Rate Recovery Mechanisms, Including a Ratemaking Proposal to Update Distribution Rates Annually and a "Lost Revenue" Recovery Mechanism, in Accordance with Ind. Code 8-1-2-42(a) and 8-1-2.5-1 *Et Seq.* and Preliminary Approval of the Estimated Costs and Scheduled Deployment of the Company's SmartGrid Initiative," **Indiana** Utility Regulatory Commission, Cause No. 43501. Direct testimony submitted February 27, 2009.

"In The Matter of the Application of Duke Energy Ohio for an Increase in Electric Distribution Rates," Public Utilities Commission of **Ohio**, Case No. 08-709-EL-AIR; "In the Matter of the Application of Duke Energy Ohio for Tariff Approval," Case No. 08-710-EL-ATA; "In the Matter of the Application of Duke Energy Ohio for Approval to Change Accounting Methods," Case No. 08-711-EL-AAM. Direct testimony submitted February 26, 2009.

"In The Matter of the Amended Application of Rocky Mountain Power for Approval of a General Rate Increase of Approximately $28.8 Million per Year (6.1 Percent Overall Average Increase)", **Wyoming** Public Service Commission, Docket No. 20000-333-ER-08. Direct testimony submitted January 30, 2009. Summary of cross answer testimony submitted February 27, 2009. Settlement testimony submitted March 13, 2009. Cross examined March 24, 2009.

"In the Matter of the Application of Dayton Power and Light Company for Approval of Its Electric Security Plan," Public Utilities Commission of **Ohio**, Case No. 08-1094-EL-SSO; "In the Matter of the Application of Dayton Power and Light Company for Approval of Revised Tariffs, Case No. 08-1095-EL-ATA; "In the Matter of the Application of Dayton Power and Light Company for Approval of Certain Accounting Authority Pursuant to Ohio Rev. Code §4905.13," Case No. 08-1096-EL-AAM; In the Matter of the Application of Dayton Power and Light Company for Approval of Its Amended Corporate Separation Plan, Case No. 08-1097-EL-UNC. Direct testimony submitted January 26, 2009. Deposed February 6, 2009. Testimony withdrawn pursuant to stipulation filed February 24, 2009.

"Application of Oncor Electric Delivery Company LLC for Authority to Change Rates," Public Utility Commission of **Texas**, SOAH Docket No. 473-08-3681, PUC Docket No. 35717. Direct testimony submitted November 26, 2008. Cross examined February 3, 2009.

"In the Matter of the Application of Columbus Southern Power Company for Approval of Its Electric Security Plan; An Amendment to Its Corporate Separation Plan; and the Sale of Certain Generating Assets", Public Utilities Commission of **Ohio**, Case No. 08-917-EL-SSO; "In the Matter of the Application of Ohio Power Company for Approval of Its Electric Security Plan; and an Amendment to Its Corporate Separation Plan," Case No. 08-918-EL-SSO. Direct testimony submitted October 31, 2008. Cross examined November 25, 2008.

"Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Base Rates," **Kentucky** Public Service Commission, Case No. 2008-00252. Direct testimony submitted October 28, 2008.

"Application of Kentucky Utilities Company for an Adjustment of Base Rates," **Kentucky** Public Service Commission, Case No. 2008-00251. Direct testimony submitted October 28, 2008.

"In the Matter of the Application of Idaho Power Company for Authority to Increase its Rates and Charges for Electric Service," **Idaho** Public Utilities Commission, Case No. IPC-E-08-10. Direct testimony submitted October 24, 2008. Rebuttal testimony submitted December 3, 2008. Cross examined December 19, 2008.

"In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service

Schedules and Electric Service Regulations," **Utah** Public Service Commission, Docket No. 08-035-38. Direct testimony submitted October 7, 2008 (test period) and February 12, 2009 (revenue requirement). Cross examined October 28, 2008 (test period).

"In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Establish a Standard Service Offer Pursuant to R.C. § 4928.143 in the Form of an Electric Security Plan," Public Utility Commission of **Ohio**, Case No. 08-935-EL-SSO. Direct testimony submitted September 29, 2008. Deposed October 13, 2008. Cross examined October 21, 2008.

"In the Matter of the Application of Westar Energy, Inc. and Kansas Gas and Electric Company for Approval to Make Certain Changes In Their Charges for Electric Service," State Corporation Commission of **Kansas**, Docket No. 08-WSEE-1041-RTS. Direct testimony submitted September 29, 2008. Cross Answer testimony submitted October 8, 2008.

"In the Matter of Appalachian Power Company's Application for Increase in Electric Rates," **Virginia** State Corporation Commission, Case No. PUE-2008-00046. Direct testimony submitted September 26, 2008.

"In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications with Reconciliation Mechanism and Tariffs for Generation Service," Public Utility Commission of **Ohio**, Case No. 08-936-EL-SSO. Direct testimony submitted September 9, 2008. Deposed September 16, 2008.

"In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return," **Arizona** Corporation Commission, Docket No. E-01345A-08-0172. Direct testimony submitted August 29, 2008 (interim rates), December 19, 2008 (revenue requirement), January 9, 2009 (cost of service, rate design), and July 1, 2009 (settlement agreement). Reply testimony submitted August 6, 2009 (settlement agreement). Cross examined September 16, 2008 (interim rates) and August 20, 2009 (settlement agreement).

"Verified Joint Petition of Duke Energy Indiana, Inc., Indianapolis Power & Light Company, Northern Indiana Public Service Company and Vectren Energy Delivery of Indiana, Inc. for Approval, if and to the Extent Required, of Certain Changes in Operations That Are Likely To Result from the Midwest Independent System Operator, Inc.'s Implementation of Revisions to Its Open Access Transmission and Energy Markets Tariff to Establish a Co-Optimized, Competitive Market for Energy and Ancillary Services Market; and for Timely Recovery of Costs Associated with Joint Petitioners' Participation in Such Ancillary Services Market," **Indiana** Utility

Regulatory Commission, Cause No. 43426. Confidential direct testimony submitted August 6, 2008. Confidential direct testimony in opposition to Settlement Agreement submitted November 12, 2008.

"In The Matter of the Application of The Detroit Edison Company for Authority to Increase Its Rates, Amend Its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority," **Michigan** Public Service Commission, Case No. U-15244. Direct testimony submitted July 15, 2008. Rebuttal testimony submitted August 8, 2008.

"Portland General Electric General Rate Case Filing," Public Utility Commission of **Oregon,** Docket No. UE-197. Direct testimony submitted July 9, 2008. Surrebuttal testimony submitted September 15, 2008.

"In the Matter of PacifiCorp, dba Pacific Power, 2009 Transition Adjustment Mechanism, Schedule 200, Cost-Based Supply Service," Public Utility Commission of **Oregon,** Docket No. UE-199. Reply testimony submitted June 23, 2008. Joint testimony in support of stipulation submitted September 4, 2008.

"2008 Puget Sound Energy General Rate Case," **Washington** Utilities and Transportation Commission, Docket Nos. UE-072300 and UG-072301. Response testimony submitted May 30, 2008. Cross-Answer testimony submitted July 3, 2008. Joint testimony in support of partial stipulations submitted July 3, 2008 (gas rate spread/rate design), August 12, 2008 (electric rate spread/rate design), and August 28, 2008 (revenue requirements). Cross examined September 3, 2008.

"Verified Petition of Duke Energy Indiana, Inc. Requesting the Indiana Utility Regulatory Commission to Approve an Alternative Regulatory Plan Pursuant to the Ind. Code 8-1-2.5, Et Seq., for the Offering of Energy Efficiency Conservation, Demand Response, and Demand-Side Management Programs and Associated Rate Treatment Including Incentives Pursuant to a Revised Standard Contract Rider No. 66 in Accordance with Ind. Code 8-1-2.5-1 Et Seq. and 8-1-2-42(a); Authority to Defer Program Costs Associated with Its Energy Efficiency Portfolio of Programs; Authority to Implement New and Enhanced Energy Efficiency Programs in Its Energy Efficiency Portfolio of Programs; and Approval of a Modification of the Fuel Adjustment Clause Earnings and Expense Tests," **Indiana** Utility Regulatory Commission, Cause No. 43374. Confidential direct testimony submitted May 21, 2008 and October 27, 2008. Testimony withdrawn pursuant to stipulation, but re-submitted June 1, 2010. Confidential supplemental direct testimony submitted June 10, 2010. Application withdrawn by Duke Energy Indiana, June 2010.

"Cinergy Corp., Duke Energy Ohio, Inc., Cinergy Power Investments, Inc., Generating Facilities LLCs," **Federal Energy Regulatory Commission**, Docket No. EC-08-78-000. Affidavit filed May 14, 2008.

"Application of Entergy Gulf States, Inc. for Authority to Change Rates and to Reconcile Fuel Costs, Public Utility Commission of **Texas**, Docket No. 34800 [SOAH Docket No. 473-08-0334]. Direct testimony submitted April 11, 2008. Testimony withdrawn pursuant to stipulation.

"Central Illinois Light Company d/b/a AmerenCILCO Proposed General Increase in Electric Delivery Service Rates, Central Illinois Public Service Company d/b/a AmerenCIPS Proposed General Increase in Electric Delivery Service Rates, Illinois Power Company d/b/a/ AmerenIP Proposed General Increase in Electric Delivery Service Rates, Central Illinois Light Company d/b/a AmerenCILCO, Proposed General Increase in Gas Delivery Service Rates, Central Illinois Public Service Company d/b/a AmerenCIPS Proposed General Increase in Gas Delivery Service Rates, Illinois Power Company d/b/a/ AmerenIP Proposed General Increase in Gas Delivery Service Rates," **Illinois** Commerce Commission, Docket Nos. 07-0585, 07-0586, 07-0587, 07-0588, 07-0589, 07-0590. Direct testimony submitted March 14, 2008. Rebuttal testimony submitted April 8, 2008.

"In the Matter of the Application of Public Service Company of Colorado for Authority to Implement an Enhanced Demand Side Management Cost Adjustment Mechanism to Include Current Recovery and Incentives," **Colorado** Public Utilities Commission, Docket No. 07A-420E. Answer testimony submitted March 10, 2008. Cross examined April 25, 2008.

"An Investigation of the Energy and Regulatory Issues in Section 50 of Kentucky's 2007 Energy Act," **Kentucky** Public Service Commission, Administrative Case No. 2007-00477. Direct testimony submitted February 29, 2008. Supplemental direct testimony submitted April 1, 2008. Cross examined April 30, 2008.

"In the Matter of the Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of Its Operations throughout the State of Arizona," **Arizona** Corporation Commission, Docket No. E-01933A-07-0402. Direct testimony submitted February 29, 2008 (revenue requirement), March 14, 2008 (rate design), and June 12, 2008 (settlement agreement). Cross examined July 14, 2008.

"Commonwealth Edison Company Proposed General Increase in Electric Rates," **Illinois** Commerce Commission, Docket No. 07-0566. Direct testimony submitted February 11, 2008. Rebuttal testimony submitted April 8, 2008.

"In the Matter of the Application of Questar Gas Company to File a General Rate Case," **Utah** Public Service Commission, Docket No. 07-057-13. Direct testimony submitted January 28, 2008 (test period), March 31, 2008 (rate of return), April 21, 2008 (revenue requirement), and August 18, 2008 (cost of service, rate spread, rate design). Rebuttal testimony submitted September 22, 2008 (cost of service, rate spread, rate design). Surrebuttal testimony submitted May 12, 2008 (rate of return) and October 7, 2008 (cost of service, rate spread, rate design). Cross examined February 8, 2008 (test period), May 21, 2008 (rate of return), and October 15, 2008 (cost of service, rate spread, rate design).

"In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations, Consisting of a General Rate Increase of Approximately $161.2 Million Per Year, and for Approval of a New Large Load Surcharge," **Utah** Public Service Commission, Docket No. 07-035-93. Direct testimony submitted January 25, 2008 (test period), April 7, 2008 (revenue requirement), and July 21, 2008 (cost of service, rate design). Rebuttal testimony submitted September 3, 2008 (cost of service, rate design). Surrebuttal testimony submitted May 23, 2008 (revenue requirement) and September 24, 2008 (cost of service, rate design). Cross examined February 7, 2008 (test period).

"In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Increase Rates for Distribution Service, Modify Certain Accounting Practices and for Tariff Approvals," Public Utilities Commission of **Ohio**, Case Nos. 07-551-EL-AIR, 07-552-EL-ATA, 07-553-EL-AAM, and 07-554-EL-UNC. Direct testimony submitted January 10, 2008.

"In the Matter of the Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Utility Service Rates in Wyoming, Consisting of a General Rate Increase of Approximately $36.1 Million per Year, and for Approval of a New Renewable Resource Mechanism and Marginal Cost Pricing Tariff," **Wyoming** Public Service Commission, Docket No. 20000-277-ER-07. Direct testimony submitted January 7, 2008. Cross examined March 6, 2008.

"In the Matter of the Application of Idaho Power Company for Authority to Increase Its Rates and Charges for Electric Service to Electric Customers in the State of Idaho," **Idaho** Public Utilities Commission, Case No. IPC-E-07-8. Direct testimony submitted December 10, 2007. Cross examined January 23, 2008.

"In The Matter of the Application of Consumers Energy Company for Authority to Increase Its Rates for the Generation and Distribution Of Electricity and Other Relief," **Michigan** Public Service Commission, Case No. U-15245. Direct testimony submitted November 6, 2007. Rebuttal testimony submitted November 20, 2007.

"In the Matter of Montana-Dakota Utilities Co., Application for Authority to Establish Increased Rates for Electric Service," **Montana** Public Service Commission, Docket No. D2007.7.79. Direct testimony submitted October 24, 2007.

"In the Matter of the Application of Public Service Company of New Mexico for Revision of its Retail Electric Rates Pursuant to Advice Notice No. 334," **New Mexico** Public Regulation Commission, Case No. 07-0077-UT. Direct testimony submitted October 22, 2007. Rebuttal testimony submitted November 19, 2007. Cross examined December 12, 2007.

"In The Matter of Georgia Power Company's 2007 Rate Case," **Georgia** Public Service Commission, Docket No. 25060-U. Direct testimony submitted October 22, 2007. Cross examined November 7, 2007.

"In the Matter of the Application of Rocky Mountain Power for an Accounting Order to Defer the Costs Related to the MidAmerican Energy Holdings Company Transaction," **Utah** Public Service Commission, Docket No. 07-035-04; "In the Matter of the Application of Rocky Mountain Power, a Division of PacifiCorp, for a Deferred Accounting Order To Defer the Costs of Loans Made to Grid West, the Regional Transmission Organization," Docket No. 06-035-163; "In the Matter of the Application of Rocky Mountain Power for an Accounting Order for Costs related to the Flooding of the Powerdale Hydro Facility," Docket No. 07-035-14. Direct testimony submitted September 10, 2007. Surrebuttal testimony submitted October 22, 2007. Cross examined October 30, 2007.

"In the Matter of General Adjustment of Electric Rates of East Kentucky Power Cooperative, Inc.," **Kentucky** Public Service Commission, Case No. 2006-00472. Direct testimony submitted July 6, 2007. Supplemental direct testimony submitted March 18, 2008.

"In the Matter of the Application of Sempra Energy Solutions for a Certificate of Convenience and Necessity for Competitive Retail Electric Service," **Arizona** Corporation Commission, Docket No. E-03964A-06-0168. Direct testimony submitted July 3, 2007. Rebuttal testimony submitted January 17, 2008 and February 7, 2007.

"Application of Public Service Company of Oklahoma for a Determination that Additional Electric Generating Capacity Will Be Used and Useful," **Oklahoma** Corporation Commission, Cause No. PUD 200500516; "Application of Public Service Company of Oklahoma for a Determination that Additional Baseload Electric Generating Capacity Will Be Used and Useful," Cause No. PUD 200600030; "In the Matter of the Application of Oklahoma Gas and Electric Company for an Order Granting Pre-Approval to Construct Red Rock Generating Facility and Authorizing a Recovery Rider," Cause No. PUD200700012. Responsive testimony submitted May 21, 2007. Cross examined July 26, 2007.

"Application of Nevada Power Company for Authority to Increase Its Annual Revenue Requirement for General Rates Charged to All Classes of Electric Customers and for Relief Properly Related Thereto," Public Utilities Commission of **Nevada**, Docket No. 06-11022. Direct testimony submitted March 14, 2007 (Phase III – revenue requirements) and March 19, 2007 (Phase IV – rate design). Cross examined April 10, 2007 (Phase III – revenue requirements) and April 16, 2007 (Phase IV – rate design).

"In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service," **Arkansas** Public Service Commission, Docket No. 06-101-U. Direct testimony submitted February 5, 2007. Surrebuttal testimony submitted March 26, 2007.

"Monongahela Power Company and The Potomac Edison Company, both d/b/a Allegheny Power – Rule 42T Application to Increase Electric Rates and Charges," Public Service Commission of **West Virginia**, Case No. 06-0960-E-42T; "Monongahela Power Company and The Potomac Edison Company, both d/b/a Allegheny Power – Information Required for Change of Depreciation Rates Pursuant to Rule 20," Case No. 06-1426-E-D. Direct and rebuttal testimony submitted January 22, 2007.

"In the Matter of the Tariffs of Aquila, Inc., d/b/a Aquila Networks-MPS and Aquila Networks-L&P Increasing Electric Rates for the Services Provided to Customers in the Aquila Networks-MPS and Aquila Networks-L&P Missouri Service Areas," **Missouri** Public Service Commission, Case No. ER-2007-0004. Direct testimony submitted January 18, 2007 (revenue requirements) and January 25, 2007 (revenue apportionment). Supplemental direct testimony submitted February 27, 2007.

"In the Matter of the Filing by Tucson Electric Power Company to Amend Decision No. 62103, **Arizona** Corporation Commission, Docket No. E-01933A-05-0650. Direct testimony submitted January 8, 2007. Surrebuttal testimony filed February 8, 2007. Cross examined March 8, 2007.

"In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area," **Missouri** Public Service Commission, Case No. ER-2007-0002. Direct testimony submitted December 15, 2006 (revenue requirements) and December 29, 2006 (fuel adjustment clause/cost-of-service/rate design). Rebuttal testimony submitted February 5, 2007 (cost-of-service). Surrebuttal testimony submitted February 27, 2007. Cross examined March 21, 2007.

"In the Matter of Application of The Union Light, Heat and Power Company d/b/a Duke Energy Kentucky, Inc. for an Adjustment of Electric Rates," **Kentucky** Public Service Commission, Case No. 2006-00172. Direct testimony submitted September 13, 2006.

"In the Matter of Appalachian Power Company's Application for Increase in Electric Rates," **Virginia** State Corporation Commission, Case No. PUE-2006-00065. Direct testimony submitted September 1, 2006. Cross examined December 7, 2006.

"In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, To Approve Rate Schedules Designed to Develop Such Return, and to Amend Decision No. 67744, **Arizona** Corporation Commission," Docket No. E-01345A-05-0816. Direct testimony submitted August 18, 2006 (revenue requirements) and September 1, 2006 (cost-of-service/rate design). Surrebuttal testimony submitted September 27, 2006. Cross examined November 7, 2006.

"Re: The Tariff Sheets Filed by Public Service Company of Colorado with Advice Letter No 1454 – Electric," **Colorado** Public Utilities Commission, Docket No. 06S-234EG. Answer testimony submitted August 18, 2006.

"Portland General Electric General Rate Case Filing," Public Utility Commission of **Oregon,** Docket No. UE-180. Direct testimony submitted August 9, 2006. Joint testimony regarding stipulation submitted August 22, 2006.

"2006 Puget Sound Energy General Rate Case," **Washington** Utilities and Transportation Commission, Docket Nos. UE-060266 and UG-060267. Response testimony submitted July 19, 2006. Joint testimony regarding stipulation submitted August 23, 2006.

"In the Matter of PacifiCorp, dba Pacific Power & Light Company, Request for a General Rate Increase in the Company's Oregon Annual Revenues," Public Utility Commission of **Oregon**, Docket No. UE-179. Direct testimony submitted July 12, 2006. Joint testimony regarding stipulation submitted August 21, 2006.

"Petition of Metropolitan Edison Company for Approval of a Rate Transition Plan," **Pennsylvania** Public Utilities Commission, Docket Nos. P-00062213 and R-00061366; "Petition of Pennsylvania Electric Company for Approval of a Rate Transition Plan," Docket Nos. P-0062214 and R-00061367; Merger Savings Remand Proceeding, Docket Nos. A-110300F0095 and A-110400F0040. Direct testimony submitted July 10, 2006. Rebuttal testimony submitted August 8, 2006. Surrebuttal testimony submitted August 18, 2006. Cross examined August 30, 2006.

"In the Matter of the Application of PacifiCorp for approval of its Proposed Electric Rate Schedules & Electric Service Regulations," **Utah** Public Service Commission, Docket No. 06-035-21. Direct testimony submitted June 9, 2006 (Test Period). Surrebuttal testimony submitted July 14, 2006.

"Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for the Approval of the Conservation Enabling Tariff Adjustment Option and Accounting Orders," **Utah** Public Service Commission, Docket No. 05-057-T01. Direct testimony submitted May 15, 2006. Rebuttal testimony submitted August 8, 2007. Cross examined September 19, 2007.

"Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, Illinois Power Company d/b/a AmerenIP, Proposed General Increase in Rates for Delivery Service (Tariffs Filed December 27, 2005)," **Illinois** Commerce Commission, Docket Nos. 06-0070, 06-0071, 06-0072. Direct testimony submitted March 26, 2006. Rebuttal testimony submitted June 27, 2006.

"In the Matter of Appalachian Power Company and Wheeling Power Company, both dba American Electric Power," Public Service Commission of **West Virginia**, Case No. 05-1278-E-PC-PW-42T. Direct and rebuttal testimony submitted March 8, 2006.

"In the Matter of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota," **Minnesota** Public Utilities Commission, Docket No. G-002/GR-05-1428. Direct testimony submitted March 2, 2006. Rebuttal testimony submitted March 30, 2006. Cross examined April 25, 2006.

"In the Matter of the Application of Arizona Public Service Company for an Emergency Interim Rate Increase and for an Interim Amendment to Decision No. 67744," **Arizona** Corporation Commission, Docket No. E-01345A-06-0009. Direct testimony submitted February 28, 2006. Cross examined March 23, 2006.

"In the Matter of the Applications of Westar Energy, Inc. and Kansas Gas and Electric Company for Approval to Make Certain Changes in Their Charges for Electric Service," State Corporation Commission of **Kansas**, Case No. 05-WSEE-981-RTS. Direct testimony submitted September 9, 2005. Cross examined October 28, 2005.

"In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Recover Costs Associated with the Construction and Ultimate Operation of an Integrated Combined Cycle Electric Generating Facility," Public Utilities Commission of **Ohio**," Case No. 05-376-EL-UNC. Direct testimony submitted July 15, 2005. Cross examined August 12, 2005.

"In the Matter of the Filing of General Rate Case Information by Tucson Electric Power Company Pursuant to Decision No. 62103," **Arizona** Corporation Commission, Docket No. E-01933A-04-0408. Direct testimony submitted June 24, 2005.

"In the Matter of Application of The Detroit Edison Company to Unbundle and Realign Its Rate Schedules for Jurisdictional Retail Sales of Electricity," **Michigan** Public Service Commission, Case No. U-14399. Direct testimony submitted June 9, 2005. Rebuttal testimony submitted July 1, 2005.

"In the Matter of the Application of Consumers Energy Company for Authority to Increase Its Rates for the Generation and Distribution of Electricity and Other Relief," **Michigan** Public Service Commission, Case No. U-14347. Direct testimony submitted June 3, 2005. Rebuttal testimony submitted June 17, 2005.

"In the Matter of Pacific Power & Light, Request for a General Rate Increase in the Company's Oregon Annual Revenues," Public Utility Commission of **Oregon**, Docket No. UE 170. Direct testimony submitted May 9, 2005. Surrebuttal testimony submitted June 27, 2005. Joint testimony regarding partial stipulations submitted June 2005, July 2005, and August 2005.

"In the Matter of the Application of Trico Electric Cooperative, Inc. for a Rate Increase," **Arizona** Corporation Commission, Docket No. E-01461A-04-0607. Direct testimony submitted April 13, 2005. Surrebuttal testimony submitted May 16, 2005. Cross examined May 26, 2005.

"In the Matter of the Application of PacifiCorp for Approval of its Proposed Electric Service Schedules and Electric Service Regulations," **Utah** Public Service Commission, Docket No. 04-035-42. Direct testimony submitted January 7, 2005.

"In the Matter of the Application by Golden Valley Electric Association, Inc., for Authority to Implement Simplified Rate Filing Procedures and Adjust Rates," Regulatory Commission of **Alaska**, Docket No. U-4-33. Direct testimony submitted November 5, 2004. Cross examined February 8, 2005.

"Advice Letter No. 1411 - Public Service Company of Colorado Electric Phase II General Rate Case," **Colorado** Public Utilities Commission, Docket No. 04S-164E. Direct testimony submitted October 12, 2004. Cross-answer testimony submitted December 13, 2004. Testimony withdrawn January 18, 2005, following Applicant's withdrawal of testimony pertaining to TOU rates.

"In the Matter of Georgia Power Company's 2004 Rate Case," **Georgia** Public Service Commission, Docket No. 18300-U. Direct testimony submitted October 8, 2004. Cross examined October 27, 2004.

"2004 Puget Sound Energy General Rate Case," **Washington** Utilities and Transportation Commission, Docket Nos. UE-040641 and UG-040640. Response testimony submitted

September 23, 2004. Cross-answer testimony submitted November 3, 2004. Joint testimony regarding stipulation submitted December 6, 2004.

"In the Matter of the Application of PacifiCorp for an Investigation of Interjurisdictional Issues," **Utah** Public Service Commission, Docket No. 02-035-04. Direct testimony submitted July 15, 2004. Cross examined July 19, 2004.

"In the Matter of an Adjustment of the Gas and Electric Rates, Terms and Conditions of Kentucky Utilities Company," **Kentucky** Public Service Commission, Case No. 2003-00434. Direct testimony submitted March 23, 2004. Testimony withdrawn pursuant to stipulation entered May 2004.

"In the Matter of an Adjustment of the Gas and Electric Rates, Terms and Conditions of Louisville Gas and Electric Company," **Kentucky** Public Service Commission, Case No. 2003-00433. Direct testimony submitted March 23, 2004. Testimony withdrawn pursuant to stipulation entered May 2004.

"In the Matter of the Application of Idaho Power Company for Authority to Increase Its Interim and Base Rates and Charges for Electric Service," **Idaho** Public Utilities Commission, Case No. IPC-E-03-13. Direct testimony submitted February 20, 2004. Rebuttal testimony submitted March 19, 2004. Cross examined April 1, 2004.

"In the Matter of the Applications of the Ohio Edison Company, the Cleveland Electric Illuminating Company and the Toledo Edison Company for Authority to Continue and Modify Certain Regulatory Accounting Practices and Procedures, for Tariff Approvals and to Establish Rates and Other Charges, Including Regulatory Transition Charges Following the Market Development Period," Public Utilities Commission of **Ohio**, Case No. 03-2144-EL-ATA. Direct testimony submitted February 6, 2004. Cross examined February 18, 2004.

"In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, To Fix a Just and Reasonable Rate of Return Thereon, To Approve Rate Schedules Designed to Develop Such Return, and For Approval of Purchased Power Contract," **Arizona** Corporation Commission, Docket No. E-01345A-03-0437. Direct testimony submitted February 3, 2004. Rebuttal testimony submitted March 30, 2004. Direct testimony regarding stipulation submitted September 27, 2004. Responsive / Clarifying testimony regarding stipulation submitted October 25, 2004. Cross examined November 8-10, 2004 and November 29-December 3, 2004.

"In the Matter of Application of the Detroit Edison Company to Increase Rates, Amend Its Rate Schedules Governing the Distribution and Supply of Electric Energy, etc.," **Michigan** Public Service Commission, Case No. U-13808. Direct testimony submitted December 12, 2003 (interim request) and March 5, 2004 (general rate case).

"In the Matter of PacifiCorp's Filing of Revised Tariff Schedules," Public Utility Commission of **Oregon**, Docket No. UE-147. Joint testimony regarding stipulation submitted August 21, 2003.

"Petition of PSI Energy, Inc. for Authority to Increase Its Rates and Charges for Electric Service, etc.," **Indiana** Utility Regulatory Commission, Cause No. 42359. Direct testimony submitted August 19, 2003. Cross examined November 5, 2003.

"In the Matter of the Application of Consumers Energy Company for a Financing Order Approving the Securitization of Certain of its Qualified Cost," **Michigan** Public Service Commission, Case No. U-13715. Direct testimony submitted April 8, 2003. Cross examined April 23, 2003.

"In the Matter of the Application of Arizona Public Service Company for Approval of Adjustment Mechanisms," **Arizona** Corporation Commission, Docket No. E-01345A-02-0403. Direct testimony submitted February 13, 2003. Surrebuttal testimony submitted March 20, 2003. Cross examined April 8, 2003.

"Re: The Investigation and Suspension of Tariff Sheets Filed by Public Service Company of Colorado, Advice Letter No. 1373 – Electric, Advice Letter No. 593 – Gas, Advice Letter No. 80 – Steam," **Colorado** Public Utilities Commission, Docket No. 02S-315 EG. Direct testimony submitted November 22, 2002. Cross-answer testimony submitted January 24, 2003.

"In the Matter of the Application of The Detroit Edison Company to Implement the Commission's Stranded Cost Recovery Procedure and for Approval of Net Stranded Cost Recovery Charges," **Michigan** Public Service Commission, Case No. U-13350. Direct testimony submitted November 12, 2002.

"Application of South Carolina Electric & Gas Company: Adjustments in the Company's Electric Rate Schedules and Tariffs," Public Service Commission of **South Carolina**, Docket No. 2002-223-E. Direct testimony submitted November 8, 2002. Surrebuttal testimony submitted November 18, 2002. Cross examined November 21, 2002.

"In the Matter of the Application of Questar Gas Company for a General Increase in Rates and Charges," **Utah** Public Service Commission, Docket No. 02-057-02. Direct testimony submitted August 30, 2002. Rebuttal testimony submitted October 4, 2002.

"The Kroger Co. v. Dynegy Power Marketing, Inc.," **Federal Energy Regulatory Commission**, EL02-119-000. Confidential affidavit filed August 13, 2002.

"In the matter of the application of Consumers Energy Company for determination of net stranded costs and for approval of net stranded cost recovery charges," **Michigan** Public Service

Commission, Case No. U-13380. Direct testimony submitted August 9, 2002. Rebuttal testimony submitted August 30, 2002. Cross examined September 10, 2002.

"In the Matter of the Application of Public Service Company of Colorado for an Order to Revise Its Incentive Cost Adjustment," **Colorado** Public Utilities Commission, Docket 02A-158E. Direct testimony submitted April 18, 2002.

"In the Matter of the Generic Proceedings Concerning Electric Restructuring Issues," **Arizona** Corporation Commission, Docket No. E-00000A-02-0051, "In the Matter of Arizona Public Service Company's Request for Variance of Certain Requirements of A.A.C. R14-2-1606," Docket No. E-01345A-01-0822, "In the Matter of the Generic Proceeding Concerning the Arizona Independent Scheduling Administrator," Docket No. E-00000A-01-0630, "In the Matter of Tucson Electric Power Company's Application for a Variance of Certain Electric Competition Rules Compliance Dates," Docket No. E-01933A-02-0069, "In the Matter of the Application of Tucson Electric Power Company for Approval of its Stranded Cost Recovery," Docket No. E-01933A-98-0471. Direct testimony submitted March 29, 2002 (APS variance request); May 29, 2002 (APS Track A proceeding/market power issues); and July 28, 2003 (Arizona ISA). Rebuttal testimony submitted August 29, 2003 (Arizona ISA). Cross examined June 21, 2002 (APS Track A proceeding/market power issues) and September 12, 2003 (Arizona ISA).

"In the Matter of Savannah Electric & Power Company's 2001 Rate Case," **Georgia** Public Service Commission, Docket No. 14618-U. Direct testimony submitted March 15, 2002. Cross examined March 28, 2002.

"Nevada Power Company's 2001 Deferred Energy Case," Public Utilities Commission of **Nevada**, PUCN 01-11029. Direct testimony submitted February 7, 2002. Cross examined February 21, 2002.

"2001 Puget Sound Energy Interim Rate Case," **Washington** Utilities and Transportation Commission, Docket Nos. UE-011570 and UE-011571. Direct testimony submitted January 30, 2002. Cross examined February 20, 2002.

"In the Matter of Georgia Power Company's 2001 Rate Case," **Georgia** Public Service Commission, Docket No. 14000-U. Direct testimony submitted October 12, 2001. Cross examined October 24, 2001.

"In the Matter of the Application of PacifiCorp for Approval of Its Proposed Electric Rate Schedules and Electric Service Regulations," **Utah** Public Service Commission, Docket No. 01-35-01. Direct testimony submitted June 15, 2001. Rebuttal testimony submitted August 31, 2001.

"In the Matter of Portland General Electric Company's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149," Public Utility Commission of **Oregon**, Docket No. UE-115. Direct testimony submitted February 20, 2001. Rebuttal testimony submitted May 4, 2001. Joint testimony regarding stipulation submitted July 27, 2001.

"In the Matter of the Application of APS Energy Services, Inc. for Declaratory Order or Waiver of the Electric Competition Rules," **Arizona** Corporation Commission, Docket No.E-01933A-00-0486. Direct testimony submitted July 24, 2000.

"In the Matter of the Application of Questar Gas Company for an Increase in Rates and Charges," **Utah** Public Service Commission, Docket No. 99-057-20. Direct testimony submitted April 19, 2000. Rebuttal testimony submitted May 24, 2000. Surrebuttal testimony submitted May 31, 2000. Cross examined June 6 & 8, 2000.

"In the Matter of the Application of Columbus Southern Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues," Public Utility Commission of **Ohio**, Case No. 99-1729-EL-ETP; "In the Matter of the Application of Ohio Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues," Public Utility Commission of **Ohio**, Case No. 99-1730-EL-ETP. Direct testimony prepared, but not submitted pursuant to settlement agreement effected May 2, 2000.

"In the Matter of the Application of FirstEnergy Corp. on Behalf of Ohio Edison Company, The Cleveland Electric Illuminating Company, and the Toledo Edison Company for Approval of Their Transition Plans and for Authorization to Collect Transition Revenues," Public Utility Commission of **Ohio**, Case No. 99-1212-EL-ETP. Direct testimony prepared, but not submitted pursuant to settlement agreement effected April 11, 2000.

"2000 Pricing Process," **Salt River Project** Board of Directors, oral comments provided March 6, 2000 and April 10, 2000.

"Tucson Electric Power Company vs. Cyprus Sierrita Corporation," **Arizona** Corporation Commission, Docket No. E-000001-99-0243. Direct testimony submitted October 25, 1999. Cross examined November 4, 1999.

"Application of Hildale City and Intermountain Municipal Gas Association for an Order Granting Access for Transportation of Interstate Natural Gas over the Pipelines of Questar Gas Company for Hildale, Utah," **Utah** Public Service Commission, Docket No. 98-057-01. Rebuttal testimony submitted August 30, 1999.

"In the Matter of the Application by Arizona Electric Power Cooperative, Inc. for Approval of Its Filing as to Regulatory Assets and Transition Revenues," **Arizona** Corporation Commission, Docket No. E-01773A-98-0470. Direct testimony submitted July 30, 1999. Cross examined February 28, 2000.

"In the Matter of the Application of Tucson Electric Power Company for Approval of its Plan for Stranded Cost Recovery," **Arizona** Corporation Commission, Docket No. E-01933A-98-0471; "In the Matter of the Filing of Tucson Electric Power Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01933A-97-0772; "In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Docket No. RE-00000C-94-0165. Direct testimony submitted June 30, 1999. Rebuttal testimony submitted August 6, 1999. Cross examined August 11-13, 1999.

"In the Matter of the Application of Arizona Public Service Company for Approval of its Plan for Stranded Cost Recovery," **Arizona** Corporation Commission, Docket No. E-01345A-98-0473; "In the Matter of the Filing of Arizona Public Service Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01345A-97-0773; "In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Docket No. RE-00000C-94-0165. Direct testimony submitted June 4, 1999. Rebuttal testimony submitted July 12, 1999. Cross examined July 14, 1999.

"In the Matter of the Application of Tucson Electric Power Company for Approval of its Plan for Stranded Cost Recovery," **Arizona** Corporation Commission, Docket No. E-01933A-98-0471; "In the Matter of the Filing of Tucson Electric Power Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01933A-97-0772; "In the Matter of the Application of Arizona Public Service Company for Approval of its Plan for Stranded Cost Recovery," Docket No. E-01345A-98-0473; "In the Matter of the Filing of Arizona Public Service Company of Unbundled Tariffs Pursuant to A.A.C. R14-2-1601 et seq.," Docket No. E-01345A-97-0773; "In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," Docket No. RE-00000C-94-0165. Direct testimony submitted November 30, 1998.

"Hearings on Pricing," **Salt River Project** Board of Directors, written and oral comments provided November 9, 1998.

"Hearings on Customer Choice," **Salt River Project** Board of Directors, written and oral comments provided June 22, 1998; June 29, 1998; July 9, 1998; August 7, 1998; and August 14, 1998.

"In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona," **Arizona** Corporation Commission, Docket No. U-0000-94-165. Direct and rebuttal testimony filed January 21, 1998. Second rebuttal testimony filed February 4, 1998. Cross examined February 25, 1998.

"In the Matter of Consolidated Edison Company of New York, Inc.'s Plans for (1) Electric Rate/Restructuring Pursuant to Opinion No. 96-12; and (2) the Formation of a Holding Company Pursuant to PSL, Sections 70, 108, and 110, and Certain Related Transactions," **New York** Public Service Commission, Case 96-E-0897. Direct testimony filed April 9, 1997. Cross examined May 5, 1997.

"In the Matter of the Petition of Sunnyside Cogeneration Associates for Enforcement of Contract Provisions," **Utah** Public Service Commission, Docket No. 96-2018-01; "In the Matter of the Application of Rocky Mountain Power for an Order Approving an Amendment to Its Power Purchase Agreement with Sunnyside Cogeneration Associates," Docket Nos. 05-035-46, and 07-035-99. Direct testimony submitted July 8, 1996. Oral testimony provided March 18, 2008.

"In the Matter of the Application of PacifiCorp, dba Pacific Power & Light Company, for Approval of Revised Tariff Schedules and an Alternative Form of Regulation Plan," **Wyoming** Public Service Commission, Docket No. 20000-ER-95-99. Direct testimony submitted April 8, 1996.

"In the Matter of the Application of Mountain Fuel Supply Company for an Increase in Rates and Charges," **Utah** Public Service Commission, Case No. 95-057-02. Direct testimony submitted June 19, 1995. Rebuttal testimony submitted July 25, 1995. Surrebuttal testimony submitted August 7, 1995.

"In the Matter of the Investigation of the Reasonableness of the Rates and Tariffs of Mountain Fuel Supply Company," **Utah** Public Service Commission, Case No. 89-057-15. Direct testimony submitted July 1990. Surrebuttal testimony submitted August 1990.

"In the Matter of the Review of the Rates of Utah Power and Light Company pursuant to The Order in Case No. 87-035-27," **Utah** Public Service Commission, Case No. 89-035-10. Rebuttal testimony submitted November 15, 1989. Cross examined December 1, 1989 (rate schedule changes for state facilities).

"In the Matter of the Application of Utah Power & Light Company and PC/UP&L Merging Corp. (to be renamed PacifiCorp) for an Order Authorizing the Merger of Utah Power & Light Company and PacifiCorp into PC/UP&L Merging Corp. and Authorizing the Issuance of Securities, Adoption of Tariffs, and Transfer of Certificates of Public Convenience and Necessity and Authorities in Connection Therewith," **Utah** Public Service Commission, Case No. 87-035-27; Direct testimony submitted April 11, 1988. Cross examined May 12, 1988 (economic impact of UP&L merger with PacifiCorp).

"In the Matter of the Application of Mountain Fuel Supply Company for Approval of Interruptible Industrial Transportation Rates," **Utah** Public Service Commission, Case No. 86-057-07. Direct testimony submitted January 15, 1988. Cross examined March 30, 1988.

"In the Matter of the Application of Utah Power and Light Company for an Order Approving a Power Purchase Agreement," **Utah** Public Service Commission, Case No. 87-035-18. Oral testimony delivered July 8, 1987.

"Cogeneration: Small Power Production," **Federal Energy Regulatory Commission**, Docket No. RM87-12-000. Statement on behalf of State of Utah delivered March 27, 1987, in San Francisco.

"In the Matter of the Investigation of Rates for Backup, Maintenance, Supplementary, and Standby Power for Utah Power and Light Company," **Utah** Public Service Commission, Case No. 86-035-13. Direct testimony submitted January 5, 1987. Case settled by stipulation approved August 1987.

"In the Matter of the Application of Sunnyside Cogeneration Associates for Approval of the Cogeneration Power Purchase Agreement," **Utah** Public Service Commission, Case No. 86-2018-01. Rebuttal testimony submitted July 16, 1986. Cross examined July 17, 1986.

"In the Matter of the Investigation of Demand-Side Alternatives to Capacity Expansion for Electric Utilities," **Utah** Public Service Commission, Case No. 84-999-20. Direct testimony submitted June 17, 1985. Rebuttal testimony submitted July 29, 1985. Cross examined August 19, 1985.

"In the Matter of the Implementation of Rules Governing Cogeneration and Small Power Production in Utah," **Utah** Public Service Commission, Case No. 80-999-06, pp. 1293-1318. Direct testimony submitted January 13, 1984 (avoided costs), May 9, 1986 (security for levelized contracts) and November 17, 1986 (avoided costs). Cross-examined February 29, 1984 (avoided costs), April 11, 1985 (standard form contracts), May 22-23, 1986 (security for levelized contracts) and December 16-17, 1986 (avoided costs).

OTHER RELATED ACTIVITY

Participant, Wyoming Load Growth Collaborative, March 2008 to January 2009.

Participant, Oregon Direct Access Task Force (UM 1081), May 2003 to November 2003.

Participant, Michigan Stranded Cost Collaborative, March 2003 to March 2004.

Member, Arizona Electric Competition Advisory Group, December 2002 to present.

Board of Directors, ex-officio, Desert STAR RTO, September 1999 to February 2002.

Member, Advisory Committee, Desert STAR RTO, September 1999 to February 2002. Acting Chairman, October 2000 to February 2002.

Board of Directors, Arizona Independent Scheduling Administrator Association, October 1998 to present.

Acting Chairman, Operating Committee, Arizona Independent Scheduling Administrator Association, October 1998 to June 1999.

Member, Desert Star ISO Investigation Working Groups: Operations, Pricing, and Governance, April 1997 to December 1999. Legal & Negotiating Committee, April 1999 to December 1999.

Participant, Independent System Operator and Spot Market Working Group, Arizona Corporation Commission, April 1997 to September 1997.

Participant, Unbundled Services and Standard Offer Working Group, Arizona Corporation Commission, April 1997 to October 1997.

Participant, Customer Selection Working Group, Arizona Corporation Commission, March 1997 to September 1997.

Member, Stranded Cost Working Group, Arizona Corporation Commission, March 1997 to September 1997.

Member, Electric System Reliability & Safety Working Group, Arizona Corporation Commission, November 1996 to September 1998.

Chairman, Salt Palace Renovation and Expansion Committee, Salt Lake County/State of Utah/Salt Lake City, multi-government entity responsible for implementation of planning, design, finance, and construction of an $85 million renovation of the Salt Palace Convention Center, Salt Lake City, Utah, May 1991 to December 1994.

State of Utah Representative, Committee on Regional Electric Power Cooperation, a joint effort of the Western Interstate Energy Board and the Western Conference of Public Service Commissioners, January 1987 to December 1990.

Member, Utah Governor's Economic Coordinating Committee, January 1987 to December 1990.

Chairman, Standard Contract Task Force, established by Utah Public Service Commission to address contractual problems relating to qualifying facility sales under PURPA, March 1986 to December 1990.

Chairman, Load Management and Energy Conservation Task Force, Utah Public Service Commission, August 1985 to December 1990.

Alternate Delegate for Utah, Western Interstate Energy Board, Denver, Colorado, August 1985 to December 1990.

Articles Editor, Economic Forum, September 1980 to August 1981.

KCH-1

Comparison of APS and AECC
Computation of Increase in Gross Revenue Requirements
For the Adjusted Test Year Ending December 31, 2010
(Thousands of Dollars)

	(a)	(b)	(c)	(d)
		ACC Jurisdiction		
Line No.	Description	APS Original Cost[1]	AECC Adjustments	AECC Original Cost
1	Adjusted Rate Base - Original Cost	$ 5,720,277	$ (305,254)	$ 5,415,023
2	Adjusted Operating Income	474,356	25,852	500,208
3	Current Rate of Return	8.29%	0.95%	9.24%
4	Required Operating Income	507,389	(27,076)	480,313
5	Requested Rate of Return	8.87%	0.00%	8.87%
6	Adjusted Operating Income Deficiency	33,033	(52,928)	(19,895)
7	Gross Revenue Conversion Factor	1.6532		1.6532
8	Adjusted Increase in Base Revenue Requirement	$ 54,610	$ (87,501)	$ (32,891)

Line No.	Description	APS FV Cost[1]	AECC Adjustments	AECC FV Cost
9	Adjusted Rate Base - RCND	10,728,532	(305,254)	10,423,278
10	Adjusted Rate Base - Fair Value (FV)	8,224,405	(305,254)	7,919,150
11	Requested Rate of Return with 1% FV Increment	6.47%	0.00%	6.47%
12	Required Operating Income	532,119	(19,751)	512,368
13	Incremental Fair Value Required Operating Income	24,730	7,325	32,055
14	Gross Revenue Conversion Factor	1.6532		1.6532
15	Fair Value Increment	40,884	12,109	52,993
16	Requested Increase in Base Revenue Requirement	$ 95,494	$ (75,392)	$ 20,102
17	Total Present Sales Revenue to Ultimate Retail Customers	$ 2,868,858	$ -	$ 2,868,858
18	Adjusted Percentage Increase	3.33%	-2.63%	0.70%

Data Sources:
1. APS Schedule A-1.

AECC Original Cost Rate Base
For the Adjusted Test Year Ending December 31, 2010
(Thousands of Dollars)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		APS Application[1] Adjusted Test Year Ended 12/31/2010		APS - Identified Updates[2] for the Test Year Ended 12/31/2010		AECC Post Test Period Plant Additions Adjustment	
Line No.	Description	Total Co.	ACC	Total Co.	ACC	Total Co.	ACC
1	Gross Utility Plant in Service	$ 14,629,039	$ 12,467,614	$ (37,241)	$ (36,108)	$ (487,308)	$ (473,580)
2	Less: Accumulated Depreciation and Amortization	5,719,580	5,015,939	(206)	(199)	(253,320)	(246,463)
3	Net Utility Plant in Service	8,909,459	7,451,675	(37,035)	(35,909)	(233,988)	(227,117)
4	Less: Total Deductions	3,720,403	3,274,062	(648)	(626)	(25,407)	(24,572)
5	Plus: Total Additions	1,654,793	1,542,664	738	502	1,504	1,043
6	Total Rate Base	$ 6,843,849	$ 5,720,277	$ (35,649)	$ (34,781)	$ (207,077)	$ (201,503)

Data Source:
1. APS SFR Schedule B-1, p. 1 of 2.
2. APS Technical Conference, October 27, 2011.

AECC RCND Rate Base
For the Adjusted Test Year Ending December 31, 2010
(Thousands of Dollars)

		APS Adjusted[1] Test Year Ended 12/31/2010		APS - Adjusted (Update) Test Year Ended 12/31/2010[2]		AECC Post Test Period Plant Additions Adjustment	
Line No.	Description	Total Co.	ACC	Total Co.	ACC	Total Co.	ACC
7	Gross Utility Plant in Service	$ 27,351,712	$ 23,201,276	$ (37,241)	$ (36,108)	$ (487,308)	$ (473,580)
8	Less: Accumulated Depreciation and Amortization	10,327,557	9,014,923	(206)	(199)	(253,320)	(246,463)
9	Net Utility Plant in Service	17,024,155	14,186,353	(37,035)	(35,909)	(233,988)	(227,117)
10	Less: Total Deductions	5,846,890	5,000,485	(648)	(626)	(25,407)	(24,572)
11	Plus: Total Additions	1,654,793	1,542,664	738	502	1,504	1,043
12	Total Rate Base	$ 12,832,058	$ 10,728,532	$ (35,649)	$ (34,781)	$ (207,077)	$ (201,503)

Data Source:
1. APS SFR Schedule B-1, p. 2 of 2.
2. APS Technical Conference, October 27, 2011.

AECC Original Cost Rate Base
For the Adjusted Test Year Ending December 31, 2010
(Thousands of Dollars)

	(a)	(b)	(c)	(d)	(e)
		AECC Renewable Generation Cost Above Market Adj.		AECC Adjusted Test Year Ended 12/31/2010	
Line No.	Description	Total Co.	ACC	Total Co.	ACC
1	Gross Utility Plant in Service	$ (73,032)	$ (70,549)	$ 14,031,458	$ 11,887,377
2	Less: Accumulated Depreciation and Amortization	(943)	(911)	5,465,111	4,768,367
3	Net Utility Plant in Service	(72,089)	(69,638)	8,566,347	7,119,011
4	Less: Total Deductions	(691)	(668)	3,693,657	3,248,197
5	Plus: Total Additions	0	0	1,657,035	1,544,209
6	Total Rate Base	$ (71,398)	$ (68,970)	$ 6,529,725	$ 5,415,023

AECC RCND Rate Base
For the Adjusted Test Year Ending December 31, 2010
(Thousands of Dollars)

		AECC Renewable Generation Cost Above Market Adj.		AECC Adjusted Test Year Ended 12/31/2010	
Line No.	Description	Total Co.	ACC	Total Co.	ACC
1	Gross Utility Plant in Service	$ (73,032)	$ (70,549)	$ 26,754,131	$ 22,621,039
2	Less: Accumulated Depreciation and Amortization	(943)	(911)	10,073,088	8,767,351
3	Net Utility Plant in Service	(72,089)	(69,638)	16,681,043	13,853,689
4	Less: Total Deductions	(691)	(668)	5,820,144	4,974,620
5	Plus: Total Additions	0	0	1,657,035	1,544,209
6	Total Rate Base	$ (71,398)	$ (68,970)	$ 12,517,934	$ 10,423,278

AECC Income Statement
For the Adjusted Test Year Ending December 31, 2010
(Thousands of Dollars)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		APS Application[1] Adjusted		APS - Identified Updates[2] for the		AECC Post Test Period *Plant Additions* Adjustment		AECC Mar. 2012 Pro Forma Sales Growth Adjustment	
Line No.	Description	Total Company	ACC Jurisdiction	Total Company	ACC Jurisdiction	Total Company	ACC Jurisdiction	Total Company	ACC Jurisdiction
	Electric Operating Revenues								
1	Revenues from Base Rates	$ 2,952,324	$ 2,868,858	$ 0	$ 0	$ 0	$ 0	$ 34,852	$ 34,852
2	Revenues from Surcharges	0	0	0	0	0	0	0	0
3	Other Eelctric Revenues	136,849	121,013	0	0	0	0	0	0
4	Total	3,089,173	2,989,871	0	0	0	0	34,852	34,852
	Operating Expenses:								
5	Electric Fuel and Purchased Power	1,040,884	1,015,598	(9,575)	(9,575)	0	0	10,966	10,966
6	Operations and Maintenance Excluding Fuel Expense	707,084	808,018	4,940	4,574	0	0	0	0
7	Depreciation and Amortization	405,150	352,026	(1,700)	(1,650)	(11,154)	(10,826)	0	0
8	Income Taxes	226,358	200,456	3,311	3,381	7,819	7,598	9,437	9,437
9	Other Taxes	162,770	139,417	(1,000)	(881)	(2,548)	(2,481)	0	0
10	Total	2,542,246	2,515,515	(4,024)	(4,151)	(5,883)	(5,709)	20,403	20,403
11	Operating Income	546,927	474,356	4,024	4,151	5,883	5,709	14,449	14,449
	Other Income (Deductions)								
12	Income Taxes	4,975	0	0	0	0	0	0	0
13	Allowance for Funds Used During Construction	22,066	0	0	0	0	0	0	0
14	Other Income (Deductions)	8,956	0	0	0	0	0	0	0
15	Other Expenses	(15,859)	0	0	0	0	0	0	0
16	Total	20,138	0	0	0	0	0	0	0
17	Income Before Interest Deductions	567,065	474,356	4,024	4,151	5,883	5,709	14,449	14,449
	Interest Deductions:								
18	Interest on Long -Term Debt	205,209	0	0	0	0	0	0	0
19	Interest on Short Term Borrowings	8,267	0	0	0	0	0	0	0
20	Debt Discount, Premium and Expense	4,559	0	0	0	0	0	0	0
21	Allowance for Borrowed Funds Used During Construction	(16,479)	0	0	0	0	0	0	0
22	Total	201,556	0	0	0	0	0	0	0
23	Net Income	$ 365,509	$ 474,356	$ 4,024	$ 4,151	$ 5,883	$ 5,709	$ 14,449	$ 14,449

Data Source:
1. APS SFR Schedule C-1.
2. APS Technical Conference, October 27, 2011.

AECC Income Statement
For the Adjusted Test Year Ending December 31, 2010
(Thousands of Dollars)

	(a)	(b)	(c)	(d)	(e)
		AECC Renewable Generation Cost Above Market Cost of Conventional Generation		AECC Proforma	
Line No.	Description	Total Company	ACC Jurisdiction	Total Company	ACC Jurisdiction
	Electric Operating Revenues				
1	Revenues from Base Rates	$ 0	$ 0	$ 2,987,176	$ 2,903,710
2	Revenues from Surcharges	0	0	0	0
3	Other Eelctric Revenues	0	0	136,849	121,013
4	Total			3,124,025	3,024,723
	Operating Expenses:				
5	Electric Fuel and Purchased Power	0	0	1,042,275	1,016,989
6	Operations and Maintenance Excluding Fuel Expense	(1,232)	(1,190)	710,792	811,402
7	Depreciation and Amortization	(2,426)	(2,343)	389,870	337,206
8	Income Taxes	2,414	2,332	249,339	223,204
9	Other Taxes	(354)	(342)	158,868	135,713
10	Total	(1,598)	(1,543)	2,551,144	2,524,515
11	Operating Income	1,598	1,543	572,880	500,208
	Other Income (Deductions)				
12	Income Taxes	0	0	4,975	0
13	Allowance for Funds Used During Construction	0	0	22,066	0
14	Other Income (Deductions)	0	0	8,956	0
15	Other Expenses	0	0	(15,859)	0
16	Total	0	0	20,138	0
17	Income Before Interest Deductions	1,598	1,543	593,018	500,208
	Interest Deductions:				
18	Interest on Long -Term Debt	0	0	205,209	0
19	Interest on Short Term Borrowings	0	0	8,267	0
20	Debt Discount, Premium and Expense	0	0	4,559	0
21	Allowance for Borrowed Funds Used During Construction	0	0	(16,479)	0
22	Total	0	0	201,556	0
23	Net Income	$ 1,598	$ 1,543	$ 391,462	$ 500,208

KCH-2

AECC RECOMMENDED RATE BASE ADJUSTMENT TO POST TEST YEAR PLANT ADDITIONS TO REFLECT 18-MONTH AVERAGE OF POST TEST PERIOD ADDITIONS

ACC JURISDICTION
(Thousands of Dollars)

Line No.	Description	AECC Solar Original Cost	Adjustment Solar Original Cost	AECC Solar @ 36% Original Cost	Line No.
1.	Adjusted Rate Base	$ 375,001	$ (201,503)	$ 173,498	*1.*
2.	Adjusted Operating Income	(18,882)	5,709	(13,173)	*2.*
3.	Current Rate of Return	-5.04%	-2.83%	-7.59%	*3.*
4.	Required Operating Income	33,263	(17,874)	15,389	*4.*
5.	Required Rate of Return	8.87%	8.87%	8.87%	*5.*
6.	Adjusted Operating Income Deficiency	52,145	(23,583)	28,562	*6.*
7.	Gross Revenue Conversion Factor	1.6532	1.6532	1.6532	*7.*
8.	Requested Increase in Base Revenue Requirements	$ 86,206	$ (38,988)	$ 47,218	*8.*
	Fair Value Impact				
9.	Estimated Fair Value Increment Revenue Requirement Impact [See Attachment KCH-4, p. 2 of 4]		7,996		*9.*
10.	Total Estimated Original Cost + Fair Value Increment Revenue Requirement Impact [= Ln. 10 + Ln. 16]		$ (30,992)		*10.*

AECC Recommended Rate Base Adjustment to Post Test Year Plant Additions

Rate Base Impact Summary

(Includes Renewable, Fossil, Nuclear, Distribution, General, and Intangible Plant Additions)

Line No.	Description	Updated 9-20-2011 Post-Test Year Plant Additions		18-Month Average Post-Test Year Plant Additions		Increase/(Decrease) From As Filed Pro Forma		Line No.
		Total Co. (A)	ACC (B)	Total Co. (C)	ACC (D)	Total Co. (E)	ACC (F)	
1.	Gross Utility Plant in Service	$ 949,526	$ 922,756	$ 462,218	$ 449,176	$ (487,308)	$ (473,580)	1.
2.	Less: Accumulated Depreciation & Amort.	504,009	490,384	250,689	243,921	(253,320)	(246,463)	2.
3	Net Utility Plant in Service	445,517	432,372	211,529	205,255	(233,988)	(227,117)	3
4.	Less: Total Deductions	49,655	48,024	24,248	23,452	(25,407)	(24,572)	4.
5.	Total Additions	(13,482)	(9,347)	(11,978)	(8,305)	1,504	1,043	5.
6.	Total Rate Base	$ 382,380	$ 375,001	$ 175,303	$ 173,498	$ (207,077)	$ (201,503)	6.
	Original Cost Impact							
7.	APS Requested Rate of Return						8.87%	7.
8.	Required Operating Income [= Ln. 6 x Ln. 7]						(17,874)	8.
9.	Gross Revenue Conversion Factor (APS SFR Schedule C-3, Ln. 5)						1.6532	9.
10.	Estimated Revenue Requirement Impact [= Ln. 8 x Ln. 9]						$ (29,549)	10.
	Fair Value Impact							
11.	Adjusted Rate Base - Fair Value (FV)						$ (201,503)	11.
12.	Requested Rate of Return with 1% FV Increment						6.47%	12.
13.	Required Operating Income [= Ln. 11 x Ln. 12]						(13,037)	13.
14.	Incremental Fair Value Required Operating Income [= Ln. 13 - Ln. 8]						4,837	14.
15.	Gross Revenue Conversion Factor (APS SFR Schedule C-3, Ln. 5)						1.6532	15.
16.	Estimated Fair Value Increment Revenue Requirement Impact [= Ln. 14 x Ln. 15]						$ 7,996	16.
17.	Total Estimated Original Cost + Fair Value Increment Revenue Requirement Impact [= Ln. 10 + Ln. 16]						$ (21,553)	17.

AECC Recommended Income Statement Adjustment to Post Test Year Plant Additions - Summary
Income Statement Impact Summary
(Includes Renewable, Fossil, Nuclear, Distribution, General, and Intangible Plant Additions)

Line No.	Description	Updated 9-20-2011 Post-Test Year Plant Additions		18-Month Average Post-Test Year Plant Additions		Increase/(Decrease) From Updated as Filed Pro Forma		Line No.
		Total Co. (K)	ACC (L)	Total Co. (M)	ACC (N)	Total Co. (O)	ACC (P)	
	Electric Operating Revenues							
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -	1.
2.	Revenues from Surcharges	-	-	-	-	-	-	2.
3.	Other Electric Revenues	-	-	-	-	-	-	3.
4.	Total Electric Operating Revenues	-	-	-	-	-	-	4.
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-	5.
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-	6.
	Other Operating Expenses:							
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-	7.
8.	Maintenance	1,935	1,869	1,935	1,869	-	-	8.
9.	Subtotal	1,935	1,869	1,935	1,869	-	-	9.
10.	Depreciation and Amortization	27,526	26,763	16,372	15,936	(11,154)	(10,826)	10.
11.	Amortization of Gain	-	-	-	-	-	-	11.
12.	Administrative and General	-	-	-	-	-	-	12.
13.	Other Taxes	10,027	9,784	7,479	7,303	(2,548)	(2,481)	13.
14.	Total	39,488	38,416	25,786	25,109	(13,702)	(13,307)	14.
15.	Operating Income Before Income Tax	(39,488)	(38,416)	(25,786)	(25,109)	13,702	13,307	15.
16.	Interest Expense	11,242	11,024	5,155	5,101	(6,087)	(5,923)	16.
17.	Taxable Income	(50,730)	(49,440)	(30,941)	(30,210)	19,789	19,230	17.
18.	Current Income Tax Rate - 39.51%	(20,043)	(19,534)	(12,225)	(11,936)	7,819	7,598	18.
19.	Operating Income (line 15 minus line 18)	$ (19,445)	$ (18,882)	$ (13,561)	$ (13,173)	$ 5,883	$ 5,709	19.
20.	Gross Revenue Conversion Factor (APS SFR Schedule C-3, Ln. 5)						1.6532	20.
21.	Estimated Revenue Requirement Impact [= -Ln 19 x Ln. 20]						$ (9,438)	21.

AECC Recommended Rate Base Adjustment to Post Test Year Plant Additions

Rate Base Impact Summary
(Renewable Energy Resources)

		(A)	(B)	(C)	(D)	(E)	(F)
		Updated 9-20-2011 Renewable Energy Resources Post-Test Year Plant Additions		18-Month Average Renewable Energy Resources Post-Test Year Plant Additions		Increase/(Decrease) From As Filed Pro Forma	
Line No.	Description	Total Co.	ACC	Total Co.	ACC	Total Co.	ACC
1.	Gross Utility Plant in Service	$ 260,765	$ 251,899	$ 114,730	$ 110,829	$ (146,035)	$ (141,070)
2.	Less: Accumulated Depreciation & Amort.	5,593	5,403	1,481	1,431	(4,112)	(3,972)
3	Net Utility Plant in Service	255,172	246,496	113,249	109,399	(141,923)	(137,098)
4.	Less: Total Deductions	3,331	3,218	1,086	1,049	(2,245)	(2,169)
5.	Total Additions	-	-	-	-	-	-
6.	Total Rate Base	$ 251,841	$ 243,278	$ 112,163	$ 108,349	$ (139,678)	$ (134,929)

Data Source: APS Response to AECC Data Request No. 2.1.

AECC Recommended Rate Base Adjustment to Post Test Year Plant Additions

Rate Base Impact Summary
(Fossil Generation Resources)

		(A)	(B)	(C)	(D)	(E)	(F)
		Updated 9-20-2011 Fossil Generation Post-Test Year Plant Additions		18-Month Average Fossil Generation Post-Test Year Plant Additions		Increase/(Decrease) From As Filed Pro Forma	
Line No.	Description	Total Co.	ACC	Total Co.	ACC	Total Co.	ACC
1.	Gross Utility Plant in Service	$ 154,606	$ 149,350	$ 90,788	$ 87,701	$ (63,818)	$ (61,649)
2.	Less: Accumulated Depreciation & Amort.	133,240	128,710	66,620	64,355	(66,620)	(64,355)
3	Net Utility Plant in Service	21,366	20,640	24,168	23,346	2,802	2,706
4.	Less: Total Deductions	12,583	12,155	6,292	6,078	(6,292)	(6,078)
5.	Total Additions	-	-	-	-	-	-
6.	Total Rate Base	$ 8,783	$ 8,485	$ 17,877	$ 17,269	$ 9,094	$ 8,784

Data Source: APS Response to AECC Data Request No. 2.2.

AECC Recommended Rate Base Adjustment to Post Test Year Plant Additions
Rate Base Impact Summary
(Nuclear Generation Resources)

		(A)	(B)	(C)	(D)	(E)	(F)
		Updated 9-20-2011 Nuclear Generation Post-Test Year Plant Additions		18-Month Average Nuclear Generation Post-Test Year Plant Additions		Increase/(Decrease) From As Filed Pro Forma	
Line No.	Description	Total Co.	ACC	Total Co.	ACC	Total Co.	ACC
1.	Gross Utility Plant in Service	$ 111,397	$ 107,609	$ 52,518	$ 50,733	$ (58,879)	$ (56,876)
2.	Less: Accumulated Depreciation & Amort.	95,937	92,675	47,969	46,338	(47,969)	(46,338)
3	Net Utility Plant in Service	15,460	14,934	4,550	4,396	(10,911)	(10,539)
4.	Less: Total Deductions	29,329	28,331	14,665	14,166	(14,665)	(14,166)
5.	Total Additions	-	-	-	-	-	-
6.	Total Rate Base	$ (13,869)	$ (13,397)	$ (10,115)	$ (9,770)	$ 3,754	$ 3,627

Data Source: APS Response to AECC Data Request No. 2.3.

AECC Recommended Rate Base Adjustment to Post Test Year Plant Additions
Rate Base Impact Summary
(Distribution, General and Intangible Plant)

		(A)	(B)	(C)	(D)	(E)	(F)
		Updated 9-2011 Distribution and General and Intangible Post-Test Year Plant Additions		18-Month Average Distribution and General and Intangible Post-Test Year Plant Additions		Increase/(Decrease) From As Filed Pro Forma	
Line No.	Description	Total Co.	ACC	Total Co.	ACC	Total Co.	ACC
1.	Gross Utility Plant in Service	$ 422,758	$ 413,898	$ 204,182	$ 199,913	$ (218,576)	$ (213,985)
2.	Less: Accumulated Depreciation & Amort.	269,239	263,596	134,620	131,798	(134,620)	(131,798)
3	Net Utility Plant in Service	153,519	150,302	69,563	68,115	(83,957)	(82,187)
4.	Less: Total Deductions	4,412	4,320	2,206	2,160	(2,206)	(2,160)
5.	Total Additions	-	-	-	-	-	-
6.	Total Rate Base	$ 149,107	$ 145,982	$ 67,357	$ 65,955	$ (81,751)	$ (80,027)

Data Source: APS Response to AECC Data Request No. 2.4.

AECC Recommended Rate Base Adjustment to Post Test Year Plant Additions

Rate Base Impact Summary
(Cash Working Capital)

		(A)	(B)	(C)	(D)	(E)	(F)
		Updated 9-20-2011 Cash Working Capital for Cost of Service Pro Formas[1]		18-Month Average Post-Test Year Plant Additions Cash Working Capital for Cost of Service Pro Formas[2]		Increase/(Decrease) From As Filed Pro Forma	
Line No.	Description	Total Co.	ACC	Total Co.	ACC	Total Co.	ACC
1.	Gross Utility Plant in Service	$ -	$ -	$ -	$ -	$ -	$ -
2.	Less: Accumulated Depreciation & Amort.	-	-	-	-	-	-
3	Net Utility Plant in Service	-	-	-	-	-	-
4.	Less: Total Deductions	-	-	-	-	-	-
5.	Total Additions	(13,482)	(9,347)	(11,978)	(8,305)	1,504	1,043
6.	Total Rate Base	$ (13,482)	$ (9,347)	$ (11,978)	$ (8,305)	$ 1,504	$ 1,043

Data Sources: 1. APS Technical Conference, October 27, 2011 Workpapers.
2. APS Response to AECC Data Request No. 2.5.

AECC Recommended Income Statement Adjustment to Post Test Year Plant Additions

Income Statement Impact Summary
(Renewable Energy Resources)

		(A)	(B)	(C)	(D)	(E)	(F)
		Updated 9-20-2011 Renewable Energy Resources Post-Test Year Plant Additions		18-Month Average Renewable Energy Resources Post-Test Year Plant Additions		Increase/(Decrease) From Updated as Filed Pro Forma	
Line No.	Description	Total Co.	ACC	Total Co.	ACC	Total Co.	ACC
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-		-		-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	1,935	1,869	1,935	1,869	-	-
9.	Subtotal	1,935	1,869	1,935	1,869	-	-
10.	Depreciation and Amortization	8,449	8,162	3,811	3,681	(4,638)	(4,480)
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	915	884	556	537	(359)	(347)
14.	Total	11,299	10,915	6,302	6,088	(4,997)	(4,827)
15.	Operating Income Before Income Tax	(11,299)	(10,915)	(6,302)	(6,088)	4,997	4,827
16.	Interest Expense	7,404	7,152	3,298	3,186	(4,106)	(3,966)
17.	Taxable Income	(18,703)	(18,067)	(9,600)	(9,274)	9,103	8,793
18.	Current Income Tax Rate - 39.51%	(7,390)	(7,138)	(3,793)	(3,664)	3,597	3,474
19.	Operating Income (line 15 minus line 18)	$ (3,909)	$ (3,777)	$ (2,509)	$ (2,424)	$ 1,400	$ 1,353

Data Source: APS Response to AECC Data Request No. 2.1.

AECC Recommended Income Statement Adjustment to Post Test Year Plant Additions

Income Statement Impact Summary
(Fossil Generation Resources)

Line No.	Description	(A) Updated 9-20-2011 Fossil Generation Post-Test Year Plant Additions — Total Co.	(B) Updated 9-20-2011 Fossil Generation Post-Test Year Plant Additions — ACC	(C) 18-Month Average Fossil Generation Post-Test Year Plant Additions — Total Co.	(D) 18-Month Average Fossil Generation Post-Test Year Plant Additions — ACC	(E) Increase/(Decrease) From As Filed Pro Forma — Total Co.	(F) Increase/(Decrease) From As Filed Pro Forma — ACC
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-		-		-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	-	-	-	-
10.	Depreciation and Amortization	4,201	4,058	2,467	2,383	(1,734)	(1,675)
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	940	908	552	533	(388)	(375)
14.	Total	5,141	4,966	3,019	2,916	(2,122)	(2,050)
15.	Operating Income Before Income Tax	(5,141)	(4,966)	(3,019)	(2,916)	2,122	2,050
16.	Interest Expense	258	249	526	508	268	259
17.	Taxable Income	(5,399)	(5,215)	(3,545)	(3,424)	1,854	1,791
18.	Current Income Tax Rate - 39.51%	(2,133)	(2,060)	(1,401)	(1,353)	733	708
19.	Operating Income (line 15 minus line 18)	$ (3,008)	$ (2,906)	$ (1,618)	$ (1,563)	$ 1,389	$ 1,342

Data Source: APS Response to AECC Data Request No. 2.2.

AECC Recommended Income Statement Adjustment to Post Test Year Plant Additions

Income Statement Impact Summary
(Nuclear Generation Resources)

Line No.	Description	(A) Total Co.	(B) ACC	(C) Total Co.	(D) ACC	(E) Total Co.	(F) ACC
		Updated 9-20-2011 Nuclear Generation Post-Test Year Plant Additions		18-Month Average Nuclear Generation Post-Test Year Plant Additions		Increase/(Decrease) From As Filed Pro Forma	
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	-	-	-	-
10.	Depreciation and Amortization	1,604	1,549	756	730	(848)	(819)
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	682	659	321	310	(361)	(349)
14.	Total	2,286	2,208	1,077	1,040	(1,209)	(1,168)
15.	Operating Income Before Income Tax	(2,286)	(2,208)	(1,077)	(1,040)	1,209	1,168
16.	Interest Expense	(408)	(394)	(297)	(287)	111	107
17.	Taxable Income	(1,878)	(1,814)	(780)	(753)	1,098	1,061
18.	Current Income Tax Rate - 39.51%	(742)	(717)	(308)	(298)	434	419
19.	Operating Income (line 15 minus line 18)	$ (1,544)	$ (1,491)	$ (769)	$ (742)	$ 775	$ 749

Data Source: APS Response to AECC Data Request No. 2.3.

AECC Recommended Income Statement Adjustment to Post Test Year Plant Additions

Income Statement Impact Summary
(Distribution, General and Intangible Plant)

		(A)	(B)	(C)	(D)	(E)	(F)
		Updated 9-20-2011 Distribution-General-Intangible Post-Test Year Plant Additions		18-Month Average Distribution and General and Intangible Post-Test Year Plant Additions		Increase/(Decrease) From As Filed Pro Forma	
Line No.	Description	Total Co.	ACC	Total Co.	ACC	Total Co.	ACC
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-		-		-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	-	-	-	-
10.	Depreciation and Amortization	13,272	12,994	9,338	9,142	(3,934)	(3,852)
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	7,490	7,333	6,050	5,923	(1,440)	(1,410)
14.	Total	20,762	20,327	15,388	15,065	(5,374)	(5,262)
15.	Operating Income Before Income Tax	(20,762)	(20,327)	(15,388)	(15,065)	5,374	5,262
16.	Interest Expense	4,384	4,292	1,980	1,939	(2,404)	(2,353)
17.	Taxable Income	(25,146)	(24,619)	(17,368)	(17,004)	7,778	7,615
18.	Current Income Tax Rate - 39.51%	(9,935)	(9,727)	(6,862)	(6,718)	3,073	3,009
19.	Operating Income (line 15 minus line 18)	$ (10,827)	$ (10,600)	$ (8,526)	$ (8,347)	$ 2,301	$ 2,253

Data Source: APS Response to AECC Data Request No. 2.4.

AECC Recommended Income Statement Adjustment to Post Test Year Plant Additions

Income Statement Impact Summary
(Cash Working Capital)

Line No.	Description	(A)	(B)	(C)	(D)	(E)	(F)
		Updated 9-20-2011 Cash Working Capital for Cost of Service Pro Formas[1]		18-Month Average Post-Test Year Plant Additions Cash Working Capital for Cost of Service Pro Formas[2]		Increase/(Decrease) From As Filed Pro Forma	
		Total Co.	ACC	Total Co.	ACC	Total Co.	ACC
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-		-		-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	-	-	-	-
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total	-	-	-	-	-	-
15.	Operating Income Before Income Tax	-	-	-	-	-	-
16.	Interest Expense	(396)	(275)	(352)	(244)	44	30
17.	Taxable Income	396	275	352	244	(44)	(30)
18.	Current Income Tax Rate - 39.51%	156	109	139	97	(17)	(12)
19.	Operating Income (line 15 minus line 18)	$ (156)	$ (109)	$ (139)	$ (97)	$ 17	$ 12

Data Sources: 1. APS Technical Conference, October 27, 2011 Workpapers.
2. APS Response to AECC Data Request No. 2.5.

KCH-3

AECC Sales Growth Adjustment

Income Statement Impact
(Thousands of Dollars)

Pro Forma Adjustment: **Mar. 2012 Sales Growth**
AECC Adjustment to APS Test Year Operations to Adjust Revenue and Fuel and Purchased Power Costs to March, 2012 Consumption.

Line No.	Description		AECC Amount	Source
1.	**REVENUES**			
2.	Operating Revenue		34,852	See Page 2
3.	Pro Forma Additional Mar. 2012 Retail Consumption (MWh)	341,921		= Ln. 9
4.	**ADJUSTED TEST YEAR FUEL AND PURCHASED POWER COSTS (¢/kWh)**			
5.	Normalized Fuel and Purchased Power Costs (¢/kWh)	3.2071		APS Technical Conference, October 27, 2011 Workpapers.
6.	**ADJUSTED TEST YEAR RETAIL SALES (MWh)**			
7.	Adjusted Test Year Retail Sales (MWh)	27,833,756		APS Technical Conference, October 27, 2011 Workpapers.
8.	Pro Forma Adjustments to Adjusted Test Year Retail Sales			
9.	To Adjust to Mar. 2012 Consumption (MWh)	341,921		= Ln. 10 - Ln. 7
10.	Mar. 2012 Retail Sales (MWh)	28,175,677		APS Response to Staff Data Request No. 3.11
11.	Pro Forma Adjustment to Fuel and Purchased Power Expenses (Line 7 x Line 11)		$ 10,966	= [Ln. 5 x Ln. 9] ÷ 1,000
12.	**Operating Income (before income tax)**		**$ 23,886**	= Ln. 2 - Ln. 11
13.	Current Income Tax Rate - 39.51%		9,437	=39.51% x Ln. 12
14.	**Operating Income After Tax**		**$ 14,449**	= Ln. 12 - Ln. 13
15.	**Gross Revenue Conversion Factor**		**1.6532**	APS SFR Schedule C-3, Ln. 5
16.	**Estimated Revenue Requirement Impact**		**$ (23,887)**	= -Ln 14 x Ln. 17

Derivation of Additional Revenue from March 2012 Sales Growth

Line No.	(a)	(b) 2010 Test Year Retail Sales[1] (MWh)	(c) 2010 Normal Weather Retail Sales Adjustment[2] (MWh)	(d) 2010 Customer Annualization Retail Sales Adjustment[2] (MWh)	(e) = (a) + (b) + (c) 2010 Adjusted Test Year Retail Sales (MWh)	(f) Twelve Months Ending Mar. 2012 Retail Sales[3] (MWh)	(g) = (f) - (e) Twelve Months Ending Mar. 2012 Sales Growth (MWh)	(h) Sch. H-2 Avg Present Revenue[4] ($/kWh)	(i) = (g) x (h) Mar. 2012 Sales Growth Revenue ($000)
1	Residential	13,035,500	39,327	25,458	13,100,285	13,234,660	134,375	$ 0.11224	$ 15,082
2	Commercial	12,361,364	77,422	(13,594)	12,425,192				
3	Industrial	2,149,128	0	0	2,149,128				
4	C&I Total	14,510,492	77,422	(13,594)	14,574,320	14,777,016	202,696	$ 0.09514	$ 19,285
5	Irrigation	20,955	0	(3,379)	17,576	21,639	4,063	$ 0.08512	$ 346
6	Hwy lighting & other pub. authority	142,516	0	(941)	141,575	142,362	787	$ 0.17717	$ 139
7	Total Retail Sales	27,709,463	116,749	7,544	27,833,756	28,175,677	341,921		$ 34,852

Data Sources:
1. APS Direct Filing Workpaper PME-WP04 2010 TY Native Load Sales
2. APS Direct Filing Workpaper CAM_WP08 Revenue Proforma Summary
3. APS Response to Staff Data Request No. 3.11 [Forecast Data 2011-2015]
4. Average present unit revenue derived from APS SFR Schedule H-2

KCH-4

AECC ADJUSTMENT TO SOLAR GENERATION POST-TEST YEAR PLANT ADDITIONS TO REMOVE COST ABOVE MARKET COST OF COMPARABLE CONVENTIONAL GENERATION FROM BASE RATES

ACC JURISDICTION
(Thousands of Dollars)

Line No.	Description	AECC Solar Original Cost	Adjustment Solar Original Cost	AECC Solar @ 36% Original Cost	*Line No.*
1.	Adjusted Rate Base	$ 108,349	$ (68,970)	$ 39,379	*1.*
2.	Adjusted Operating Income	(2,424)	1,543	(881)	*2.*
3.	Current Rate of Return	-2.24%	-2.24%	-2.24%	*3.*
4.	Required Operating Income	9,611	(6,118)	3,493	*4.*
5.	Required Rate of Return	8.87%	8.87%	8.87%	*5.*
6.	Adjusted Operating Income Deficiency	12,035	(7,661)	4,374	*6.*
7.	Gross Revenue Conversion Factor	1.6532	1.6532	1.6532	*7.*
8.	Requested Increase in Base Revenue Requirements	$ 19,896	$ (12,665)	$ 7,230	*8.*
	Fair Value Impact				
9.	Estimated Fair Value Increment Revenue Requirement Impact [See Attachment KCH-4, p. 2 of 4]		2,737		*9.*
10.	Total Estimated Original Cost + Fair Value Increment Revenue Requirement Impact [= Ln. 10 + Ln. 16]		**$ (9,928)**		*10.*

AECC ADJUSTMENT TO SOLAR GENERATION POST-TEST YEAR PLANT ADDITIONS TO REMOVE COST ABOVE MARKET COST OF COMPARABLE CONVENTIONAL GENERATION FROM BASE RATES

Rate Base Impact
(Thousands of Dollars)

		AECC18-Month Average Renewable Energy Resources Post-Test Year Plant Additions		Allowable Portion of 18-Month Average Renewable Energy Resources Post-Test Year Plant Additions Below Market Cost of Comparable Conventional Generation		AECC Recommended Adjustment for Renewable Generation Costs Above the Market Cost oF Comparable Conventional Generation		
Line No.	Description	Total Co.	ACC	Total Co.	ACC	Total Co.	ACC	*Line No.*
	(A)	(E)	(I)	(E)	(I)	(E)	(I)	
1.	Gross Utility Plant in Service	$ 114,730	$ 110,829	$ 41,698	$ 40,281	$ (73,032)	$ (70,549)	*1.*
2.	Less: Accumulated Depreciation & Amort.	1,481	1,431	538	520	(943)	(911)	*2.*
3	Net Utility Plant in Service	113,249	109,399	41,160	39,761	(72,089)	(69,638)	*3*
4.	Less: Total Deductions	1,086	1,049	395	381	(691)	(668)	*4.*
5.	Total Additions	-	-	-	-	-	-	*5.*
6.	Total Rate Base	$ 112,163	$ 108,349	$ 40,765	$ 39,379	$ (71,398)	$ (68,970)	*6.*
	Original Cost Impact							
7.	APS Requested Rate of Return						8.87%	*7.*
8.	Required Operating Income [= Ln. 6 x Ln. 7]						(6,118)	*8.*
9.	Gross Revenue Conversion Factor (APS SFR Schedule C-3, Ln. 5)						1.6532	*9.*
10.	Estimated Revenue Requirement Impact [= Ln. 8 x Ln. 9]						$ (10,114)	*10.*
	Fair Value Impact							
11.	Adjusted Rate Base - Fair Value (FV)						$ (68,970)	*11.*
12.	Requested Rate of Return with 1% FV Increment						6.47%	*12.*
13.	Required Operating Income [= Ln. 11 x Ln. 12]						(4,462)	*13.*
14.	Incremental Fair Value Required Operating Income [= Ln. 13 - Ln. 8]						1,655	*14.*
15.	Gross Revenue Conversion Factor (APS SFR Schedule C-3, Ln. 5)						1.6532	*15.*
16.	Estimated Fair Value Increment Revenue Requirement Impact [= Ln. 14 x Ln. 15]						$ 2,737	*16.*
17.	Total Estimated Original Cost + Fair Value Increment Revenue Requirement Impact [= Ln. 10 + Ln. 16]						$ (7,377)	*17.*

AECC ADJUSTMENT TO SOLAR GENERATION POST-TEST YEAR PLANT ADDITIONS
TO REMOVE COST ABOVE MARKET COST OF COMPARABLE CONVENTIONAL GENERATION FROM BASE RATES

Income Statement Impact
(Thousands of Dollars)

		AECC18-Month Average Renewable Energy Resources Post-Test Year Plant Additions		Allowable Portion of 18-Month Average Renewable Energy Resources Post-Test Year Plant Additions Below Market Cost of Comparable Conventional Generation		AECC Recommended Adjustment for Renewable Generation Costs Above the Market Cost of Comparable Conventional Generation		
Line No.	Description	Total Co. (E)	ACC (I)	Total Co. (E)	ACC (I)	Total Co. (E)	ACC (I)	Line No.
	Electric Operating Revenues							
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -	1.
2.	Revenues from Surcharges	-	-	-	-	-	-	2.
3.	Other Electric Revenues	-	-	-	-	-	-	3.
4.	Total Electric Operating Revenues	-	-	-	-	-	-	4.
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-	5.
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-	6.
	Other Operating Expenses:							
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-	7.
8.	Maintenance	1,935	1,869	703	679	(1,232)	(1,190)	8.
9.	Subtotal	1,935	1,869	703	679	(1,232)	(1,190)	9.
10.	Depreciation and Amortization	3,811	3,681	1,385	1,338	(2,426)	(2,343)	10.
11.	Amortization of Gain	-	-	-	-	-	-	11.
12.	Administrative and General	-	-	-	-	-	-	12.
13.	Other Taxes	556	537	202	195	(354)	(342)	13.
14.	Total	6,302	6,088	2,290	2,213	(4,012)	(3,875)	14.
15.	Operating Income Before Income Tax	(6,302)	(6,088)	(2,290)	(2,213)	4,012	3,875	15.
16.	Interest Expense	3,298	3,186	1,199	1,158	(2,099)	(2,028)	16.
17.	Taxable Income	(9,600)	(9,274)	(3,489)	(3,370)	6,111	5,903	17.
18.	Current Income Tax Rate - 39.51%	(3,793)	(3,664)	(1,379)	(1,332)	2,414	2,332	18.
19.	Operating Income (line 15 minus line 18)	$ (2,509)	$ (2,424)	$ (911)	$ (881)	$ 1,598	$ 1,543	19.
20.	Gross Revenue Conversion Factor (APS SFR Schedule C-3, Ln. 5)						1.6532	20.
21.	Estimated Revenue Requirement Impact [= -Ln 19 x Ln. 20]						$ (2,551)	21.

Derivation of AECC's Recommended Percentage of Renewable Generation Allowed to be Transferred from the RES to Base Rates

Line No.	(a) Description	(b) NPV $M	(c) NPV GWh	(d) = (b) ÷ (c) NPV $/MWh	Source
1	Combined 35 Year (Bid Term) NPV of AZ Sun Solar Projects @ 8.01%	[redacted]			APS CONFIDENTIAL Response to AECC DR No. 4.1-2(a)
		Nominal $M	Nominal GWh	Nominal $/MWh	
2	APS Avoided Cost for Calendar Year 2012	[redacted]			APS CONFIDENTIAL Response to AECC DR No. 4.1-2(a)
3	Percent AZ Sun Projects Bid Above APS Avoided Cost			[redacted]	= Ln 1 ÷ Ln. 2
4	Percent of AZ Sun Projects below AC			36%	= Ln 2 ÷ Ln. 1
5	Percent of AZ Sun Projects Above AC			64%	= 100% - Ln. 4

KCH-5

AECC ADJUSTMENT TO SYSTEM BENEFIT CHARGE EXPENSE
TEST YEAR ENDING 12/31/2010

Line No.	Description	Total Company	ACC Jurisdiction	Allocator
1.	Operating Expenses (Actual Test Year 2010)			
2.	DSM	10,000,000	10,000,000	1.0000
3.	Four Corners & Navajo Coal Reclamation	1,722,817	1,680,982	0.9757
4.	ISFSI	5,233,000	5,105,928	0.9757
5.	Palo Verde Decommissioning	19,198,000	18,731,817	0.9757
6.	E-3 & E-4 Discounts	10,674,321	10,674,321	1.0000
7.	Total Operating Expenses	46,828,138	46,193,047	
8.	Operating Expenses (APS Proforma)			
9.	ISFSI Expense Update - APS Adjustment # 10 (Sch C-2, p. 4, line 5)	(4,236,000)	(4,133,138)	0.9757
10.	Palo Verde Decommissioning - APS Adjustment #10 (Sch. C-2, p. 4, line 10)	(2,947,000)	(2,875,438)	0.9757
11.	Coal Reclamation - APS Adjustment #20 (Sch C-2, p. 7, line 5)	6,216,000	6,065,057	0.9757
12.	Total Operating Expenses	(967,000)	(943,518)	
13.	APS Proposed Total System Benefits Expenses	45,861,138	45,249,529	
14.	AECC Adjustment to APS Proforma System Benefit Operating Expense:	(8,920,975)	(8,704,348)	0.9757
15.	AECC Recommended Total System Benefits Expenses	36,940,163	36,545,181	

Data Sources: APS Response to Staff Inf. 2.1, Attachment APS14996 and JCL_WP22 IS

AECC SYSTEM BENEFITS CHARGE CALCULATION
TEST YEAR ENDING 12/31/2010

Line No.	Description		
1.	APS Proposed System Benefits Revenue Requirement	$	45,249,529
2.	Energy Consumption @ Customer Level (kWh)		27,448,414,000
3.	APS Proposed System Benefits Unit Cost ($/kWh)		$0.00165
4.	AECC Recommended System Benefits Revenue Requirement	$	36,545,181
5.	Energy Consumption @ Customer Level (kWh)		27,448,414,000
6.	AECC Recommended System Benefits Unit Cost ($/kWh)		$0.00133
7.	AECC Adjustment to APS Proposed System Benefit Unit Cost ($/kWh)		($0.00032)

Data Source: APS Response to Staff 24.7, Attachment APS14933